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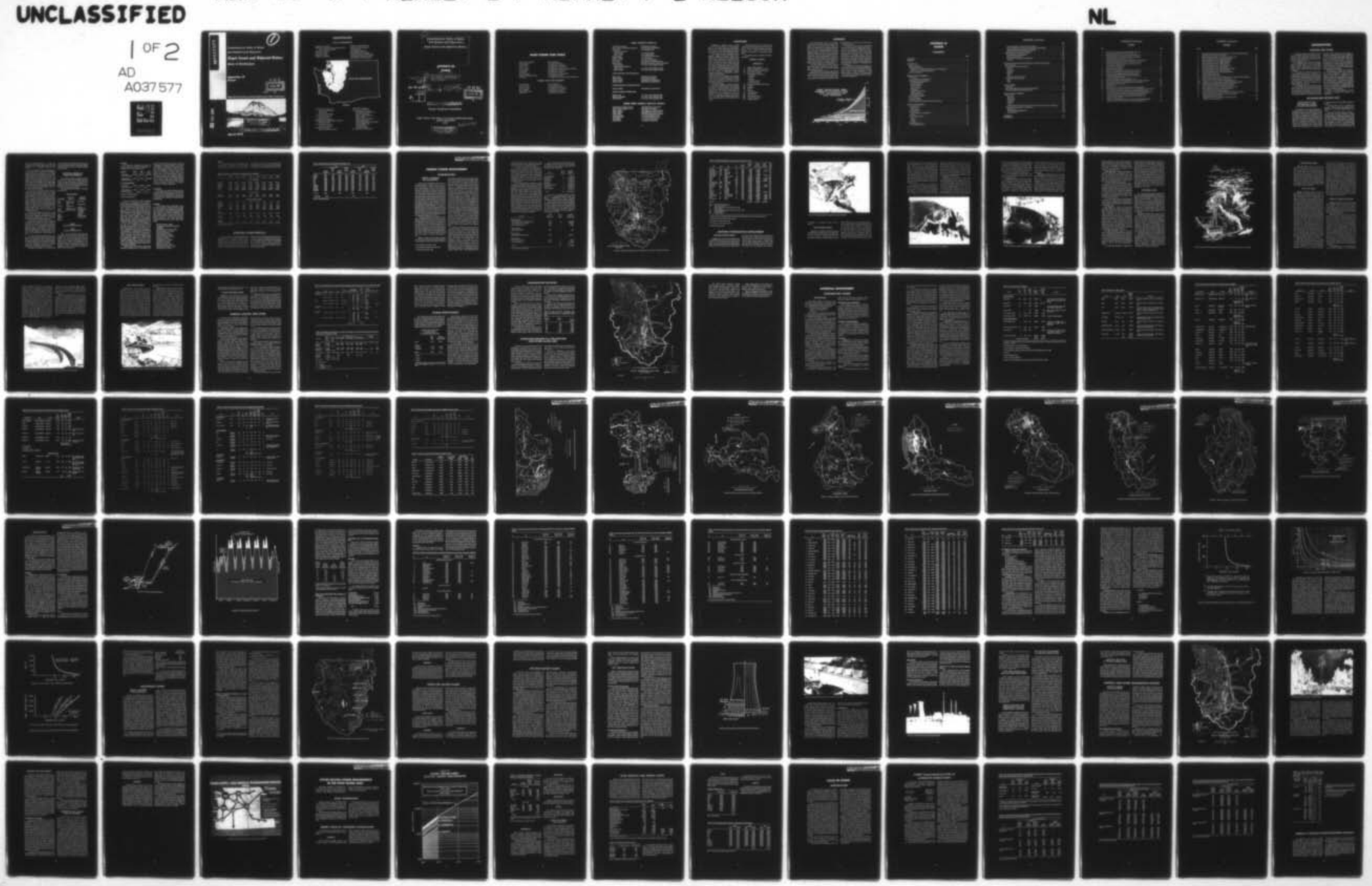

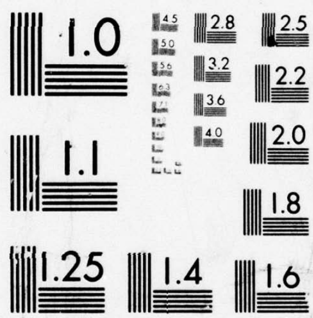

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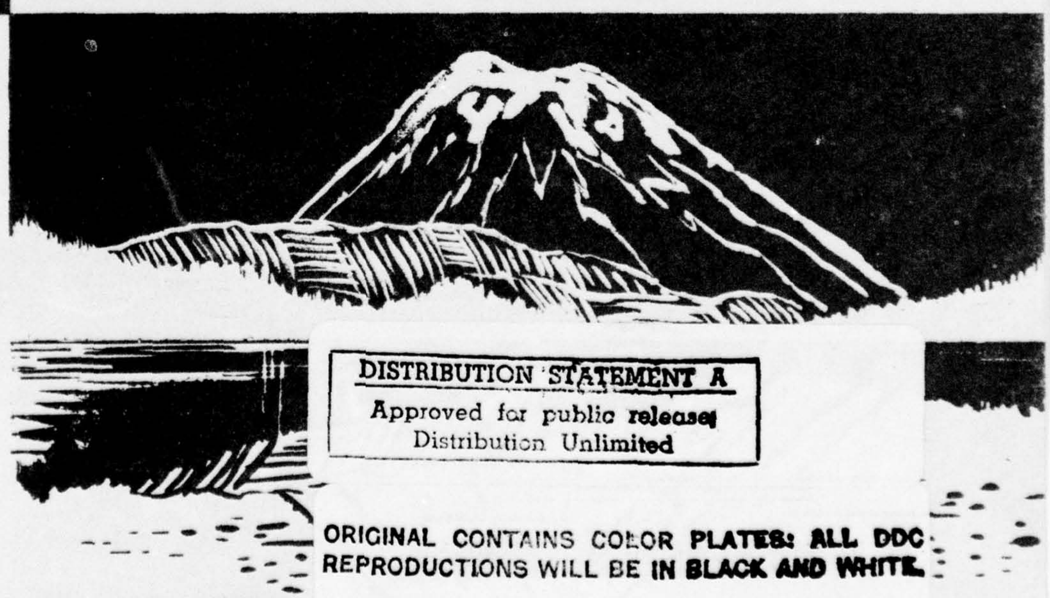
Comprehensive Study of Water
and Related Land Resources

Puget Sound and Adjacent Waters

State of Washington

Appendix IX
Power

Puget Sound Task Force—Pacific Northwest River Basins Commission



March 1970

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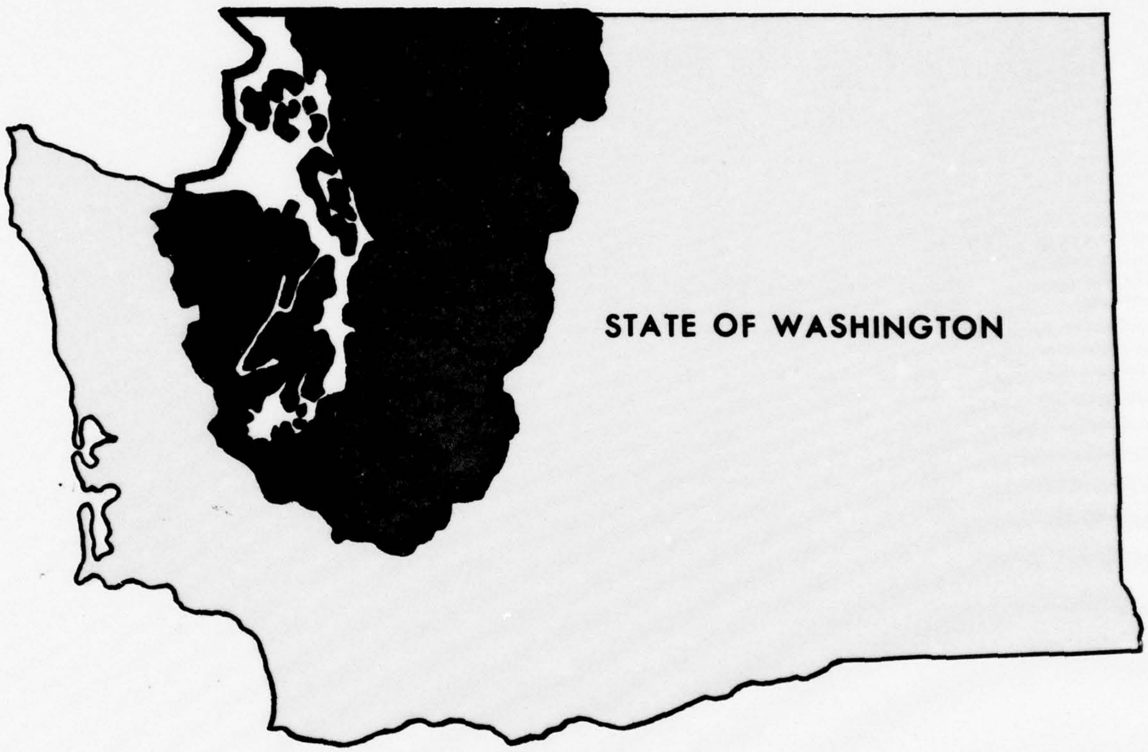
Department of Commerce & Economic Development
Office of Nuclear Development
Department of Fisheries
Department of Game
Department of Health
Department of Highways
Department of Natural Resources
Department of Water Resources
Canal Commission
Oceanographic Commission
Parks and Recreation Commission
Planning and Community Affairs Agency
Soil and Water Conservation Committee
Water Pollution Control Commission



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Federal Power Commission
U.S. Department of the Interior
Bonneville Power Administration
Bureau of Indian Affairs
Bureau of Land Management
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Bureau of Outdoor Recreation
Bureau of Reclamation
Federal Water Pollution Control Admin.
Fish and Wildlife Service
Geological Survey
National Park Service
U.S. Department of Transportation

Comprehensive Study of Water and Related Land Resources, Puget Sound and Adjacent Waters.

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APPENDIX IX.

POWER

10

Alfred T./Neale, Sydney/Steinborn,
Lewis F./Kehne, Ernest E./Allen
Francis L./Nelson

11 Mar 70

12 107p.

Power Technical Committee

PUGET SOUND TASK FORCE of the PACIFIC NORTHWEST RIVER BASINS COMMISSION
1970

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FOREWORD

APPENDIX IX, POWER, contains a detailed report of one component of the Comprehensive Water Resource Study of Puget Sound and Adjacent Waters. It is one of the technical appendices providing supporting data for the overall water resource Study.

The Summary Report is supplemented by 15 appendices. Appendix I contains a Digest of Public Hearings. Appendices II through IV contain environmental studies. Appendices V through XIV each contain an inventory of present status, present and future needs, and the means to satisfy the needs, based upon a single use or control of water. Appendix XV contains comprehensive plans for the Puget Sound Area and its individual basins and describes the development of these multiple-purpose plans including the trade-offs of single-purpose solutions contained in Appendices V through XIV, to achieve multiple planning objectives.

The purpose of this appendix is to (1) appraise the extent of present power development in the Puget Sound Area; (2) determine the potential for power development; and (3) identify the means for meeting the power demands.

River-basin planning in the Pacific Northwest was started under the guidance of the Columbia Basin Inter-Agency Committee (CBIAC) and completed under the aegis of the Pacific Nortwest River Basins Commission. A Task Force for Puget Sound and Adjacent Waters was established in 1964 by the CBIAC for the purpose of making a water resource study of the Puget Sound based upon guidelines set forth in Senate Document 97, 87th Congress, Second Session.

The Puget Sound Task Force consists of ten members, each representing a major State or Federal agency. All State and Federal agencies having some authority over or interest in the use of water resources are included in the organized planning effort.

The published report is contained in the following volumes:

SUMMARY REPORT

APPENDICES

I. Digest of Public Hearings
II. Political and Legislative Environment
III. Hydrology and Natural Environment
IV. Economic Environment
V. Water-Related Land Resources
  a. Agriculture
  b. Forests
  c. Minerals
  d. Intensive Land Use
  e. Future Land Use
VI. Municipal and Industrial Water Supply
VII. Irrigation
VIII. Navigation
IX. Power
X. Recreation
XI. Fish and Wildlife
XII. Flood Control
XIII. Water Quality Control
XIV. Watershed Management
XV. Plan Formulation

SUMMARY

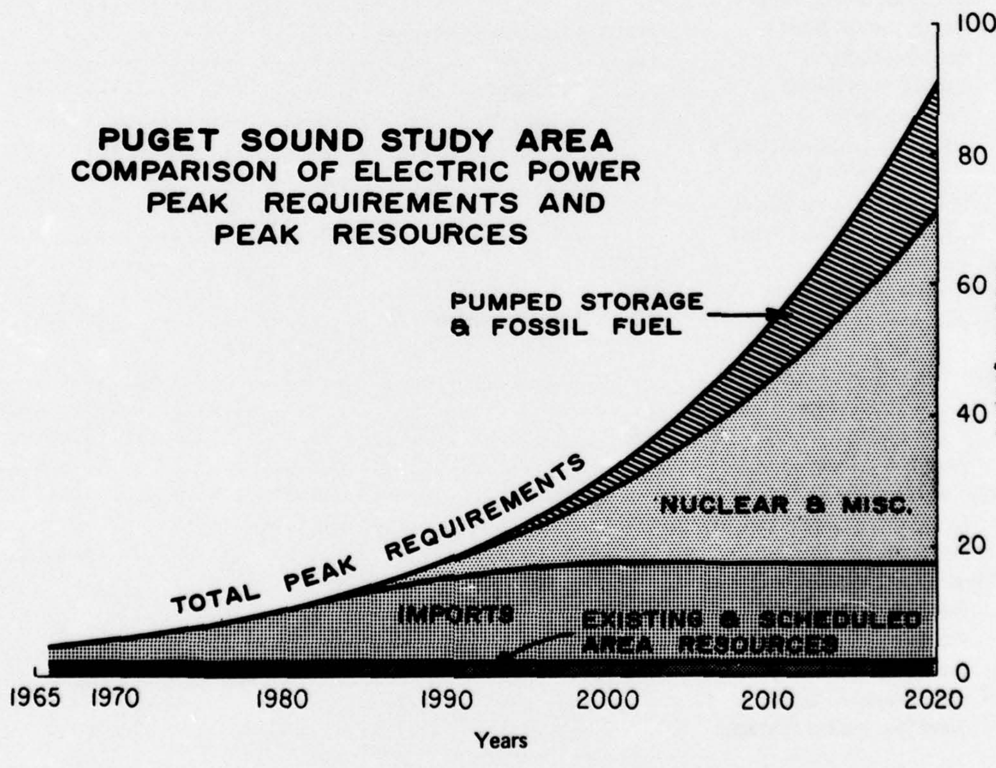
The electric power resources of the Puget Sound Area met the electric power requirement or demand of the Area until the early 1940's. The demand for electric power rose rapidly during World War II and the Area began importing electricity. Today, two-thirds of the peak demand of over 3,500 megawatts (mw) for the Area is met from outside sources. By 1980, the Area will need 9,700 mw, almost three times the present demand. The Area can supply only 1,800 mw of this need with 1,200 mw at existing plants and almost 600 mw at possible new projects and additions to existing hydroelectric plants. Importation will meet the remaining need.

The major outside source of power is from the upper and middle Columbia River hydroelectric plants. These plants will reach ultimate installed capacity by the late 1990's.

The Puget Sound Area will have a peak demand of 30,000 mw by the year 2000, almost ten times the present demand. Early in the period 1980-2000, the Area will begin developing nuclear-fueled steam-electric plants. Pumped-storage hydroelectric plants will develop late in the period to meet the demand for peaking generation.

The Area has a high potential for development of nuclear-electric power, utilizing various types of cooling, and pumped-storage hydroelectric sites to meet the power demands to 2020. These power resources will also meet the political and legislative requirements of development, such as State and national parks, water quality standards, etc. Therefore, by the year 2020, when the electric power peak requirement is forecasted at almost 90,000 mw, nearly 30 times the present demand, pumped-storage and nuclear-electric generation will predominate in meeting the load.

The graph below illustrates the development of electric power resources in meeting the peak requirements from 1965 to 2020. The nuclear and miscellaneous portion includes geothermal or other unknown sources of generation. The pumped-storage and fossil-fuel portion includes possible gas turbine or steam-electric peaking plants.



APPENDIX IX
POWER

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INTRODUCTION

PURPOSE AND SCOPE

This appendix appraises the aspects of electric power development in the Puget Sound Study Area. Included in this appraisal are the present power situation, the power needs of the Study Area, and the means for meeting those needs.

The geographic and economic relationships between the Puget Sound Area and the surrounding Pacific Northwest Region are very strong. These factors as well as multi-purpose uses in specific projects must be considered to achieve comprehensive development.

The existing and potentially feasible hydroelectric projects can serve only a small part of the increasing load in the Study Area. As this load grows, it must be met through development of other sources of power such as fossil-fuel, nuclear or geothermal, and importation from outside the Area. Any new power importation will require additional transmission facilities into the Area.

This appendix presents the needs in terms of electric power loads and the means for meeting these needs or loads. The power loads and power sources for meeting them are projected to the years 1980, 2000, and 2020. These projections provide the basis for planning consistent with long-range comprehensive water resource development. The estimates of 1980 power requirements are based on an evaluation of the trend of past loads and possible changes in the economy which would increase power loads. Estimates of the 1980 power sources to meet these requirements are the result of a rigorous appraisal of the capabilities of existing sources and the value of potential hydroelectric and possible thermal power supply. Estimates for the target years 2000 and 2020 are necessarily more generalized.

Cooperation by the Federal, State of Washington, and local agencies involved in water and related land resource development of Puget Sound and adjacent waters made the preparation of this appendix possible. The power aspects for the comprehensive plan of resource development are evaluated in the concluding section of this appendix. In keeping with the methodology employed in the comprehensive study of Puget Sound and Adjacent Waters, the power study was undertaken on a single-purpose basis for use in developing the Comprehensive Plan (see Appendix XV, Plan Formulation).

Research on weather modification to enhance precipitation is continuing. This subject is not covered herein.

BACKGROUND INFORMATION

DESCRIPTION OF AREA AND REGIONAL NATURE OF POWER DEVELOPMENT

Development of power loads and resources in the Puget Sound Area is an important factor in the physical and economic growth of the Pacific Northwest Region. Policies, plans and programs for the conservation and beneficial use of the Area's water, land and mineral resources are all affected by power development. The physical geography of the Area is altered by construction and operation of hydroelectric and thermal-electric power plants, storage reservoirs and transmission lines. Low-cost power, abundant and widely available, is an important factor in expanding industry and the general economy of the Area.

The Puget Sound Area as a producer and consumer of electric power will continue to be an integral part of the Pacific Northwest power economy.

The Pacific Northwest Region is served on a coordinated basis through a number of interconnected generating and transmission systems in which the Federal regional transmission grid of the Bonneville Power Administration provides the backbone lines. At present, the Northwest is almost entirely hydro-supplied, but a shift to a mixed thermal and hydro system should be well underway by 1980, when the bulk of the economical hydro energy will

have been developed. However, it is likely that economic hydro peaking capacity may be under development for a considerable period after that time.

Future hydroelectric power development for the most part will be in connection with multiple-purpose projects and systems both in the Pacific Northwest at large and the Puget Sound Area. The Area is deficient in water power resources. It is expected that the Area will continue to be a large importer of electrical energy from the rest of the Pacific Northwest, principally the Columbia Basin. The average annual energy generated from falling water in the Area, now meeting roughly 30 percent of the Area's loads will meet only about 1.0 or 1.5 percent of those loads by 2020.

The rivers in the Puget Sound Area have hydroelectric power potential. Some of the reasons why the potential should be considered in comprehensive planning are: (a) the resource could meet a portion of the Area's loads, (b) water power development in conjunction with other multi-purpose water uses may improve the economic feasibility of many projects, (c) the proximity of streams to load centers enhances the value of their power-peaking potential, and (d) the high winter flow characteristics of the streams, unlike those of the main stem of the Columbia River, coincide with the maximum power demands of the Area.

Coal, once a valuable natural resource in the Puget Sound Study Area, has dropped to a small fraction of the maximum tons attained. Very little of the estimated 2.0 billion tons of coal in the Study Area is economically mineable at present rates.

Nuclear power plants will enter the scene as permitted by the economics of location, competitive cost and siting criteria. Nuclear power is presently believed to be in a strong competitive position with alternative sources of thermal power in the Pacific Northwest. Nuclear plants might be located at tidewater on Puget Sound, on the Pacific Ocean to the west, on the Columbia River, or other streams to the east.

For years, hydroelectric generation was considered to be the answer to electrical demands. With most of the hydroelectric power resources already developed, fossil-fuel and nuclear power development are gaining momentum in the Pacific Northwest power field. Geothermal resources may also be developed to help fill the future need for power.

Preliminary investigations of the geothermal resource potential of the Puget Sound Area and other parts of Washington have been made. More intensive exploratory studies will have to be made to pinpoint the best sources.

HISTORICAL GROWTH IN POWER REQUIREMENTS

The Pacific Northwest, including the Puget Sound Area, is a heavy user of electrical capacity and energy, currently using power at about twice the national per capita rate. The Pacific Northwest rate of load growth in the last two decades has been about the same as the national rate of growth.

The operating electrical utilities in the Puget Sound Area are:

Public Non-Federal

Municipalities	Public Utility Districts	Cooperatives & Mutuals
Blaine	Clallam Co. PUD	Alder Mutual
DuPont	Mason Co. PUD No. 1	Elmhurst Mutual
Eatonville	Mason Co. PUD No. 3	Lakeview
Fircrest	Snohomish Co. PUD	Loveland Mutual
Milton	Whatcom Co. PUD	Ohop Mutual
Port Angeles		Orcas Power & Light Co.
Ruston		Parkland
Seattle		Peninsula Light Co.
Steilacoom		Tanner Electric
Sumas		
Tacoma		

Federal

Bonneville Power Administration

Private

Puget Sound Power & Light Co.

Table 1 shows the growth in electrical power requirements in the Puget Sound Area from 1950 through 1965. Over the past fourteen years, the annual rate of growth has averaged about 7 percent. Energy sales to domestic customers grew at the greatest annual rate, 8.5 percent, followed by commercial at 7.6 percent and industrial at 5.2 percent. A discussion of some of the factors influencing the growth of these classes follows.

Domestic

The growth in population and number of domestic customers for the State of Washington and the Puget Sound Area are listed as follows:

Population	1950[1]	1960[1]	1965
State of Wash.	2,378,963	2,853,214	3,002,055[2]
Annual rate of growth		1.8%	1.0%
Puget Sound Area	1,418,422	1,768,117	1,877,500[2]
Annual rate of growth		2.2%	1.2%
No. of Domestic Customers			
State of Wash.	683,897	889,848	984,616
Annual rate of growth		2.7%	2.0%
Puget Sound Area	418,518	552,706	626,157
Annual rate of growth		2.8%	2.5%

[1] Source: U.S. Bureau of Census.

[2] BPA Economic Base Study

The rate of growth in domestic customers exceeds that of the population for a number of reasons. One is the rapid increase in seasonal homes in the Area. During the 1950-1960 decade, the annual rate of increase for these second homes was more than 5 percent in the Puget Sound Area. All indications are that this rate has been surpassed since 1960. The portion of the population not in housing units is found in group quarters in institutions, dormitories, barracks, rooming houses, or other places where the occupants do not have separate living arrangements. The percent of the population in housing units has increased considerably from 1950 to 1960. In 1950, 85.6 percent of the population in the Area was in housing units. By 1960, this percentage had increased to 89.9 percent. For the State, the percentages were 94.3 in 1950 and 97.4 in 1960. Contributing to the increase in the proportion of the population in housing units between 1950 and 1960 for the Area is the decrease in the number of military personnel at Fort Lewis. According to the census, the number of persons per occupied dwelling has changed only slightly from 1950 to 1960. Occupied dwellings shown in census data and the number of domestic customers counted by utilities are not fully comparable because of differences in classification and definition.

Average energy use per domestic customer has increased at a slightly lower rate in the Puget Sound Area over the past fourteen years than for the State of Washington, 5.6 percent compared to 5.8 percent. Contributing to this difference is the lower use of electric space heating in the Area than for the State. From data supplied by utilities serving over 85 percent of the domestic customers, electric space heating used for the Area amounted to about 15 percent of the total in 1965 compared to 20 percent for the State. Since the use in 1950 was probably less than 1 percent, electric space heating increases accounts for about 2,000 kwh, more than one-third, of the total increase in average use by domestic customers over the past fourteen years.

Commercial

The number of domestic customers per commercial customer increased from 8.16 in 1950 to 9.41 in 1960 and then increased slightly to 9.45 in 1965. Commercial electric energy sales have increased due to the greater use of lighting, air conditioning, and electric heating.

Industrial

The Bonneville Power Administration serves five industrial plants in the Puget Sound Area. These are Crown Zellerbach and Rayonier at Port Angeles, Kaiser Aluminum at Tacoma, the Puget Sound Navy Yard at Bremerton, and Intalco at Bellingham. The Kaiser Aluminum plant was shut down in 1958 and reopened for production in October 1964 and subsequently expanded in 1969. Other major power consuming industrial plants served by other utilities include:

Bethlehem Steel Co.–Seattle
Georgia-Pacific–Pulp & Timber Division–Bellingham
Boeing Aircraft Co.–Renton, Seattle
Hooker Chemical Co.–Tacoma
Jorgensen Steel–Seattle
Northwest Steel Co.–Seattle
Pacific Car & Foundry–Renton
Pennsalt Co.–Tacoma
St. Regis Paper Co.–Tacoma
Scott Paper Co.–Everett
Shell Oil Co.–Anacortes
Simpson Timber Co.–Shelton
West Tacoma Newsprint–Tacoma
Weyerhaeuser Co.–Everett

Other

These sales include street lighting, public authorities, military establishments, and other miscellaneous customers. Included in these sales are two Federal agency customers of the Bonneville Power Administration, the U.S. Naval Complex at Bremerton, and the U.S. Naval Radio Station at Jim Creek.

TABLE 1. Electric power requirements in Puget Sound Area, 1950-1965

	1950	1955	1960	1961	1962	1963	1964	1965
				Types of Customers				
Domestic	418,518	485,590	552,706	566,002	588,965	601,222	610,782	626,157
Irrigation	129	235	190	206	218	228	225	535
Commercial	51,306	56,202	58,723	60,191	62,596	64,731	65,415	66,240
Industrial	2,375	1,844	2,254	2,292	2,303	2,316	2,316	2,395
Other	1,254	1,580	1,892	1,968	2,129	2,212	2,365	2,442
Total	473,582	545,451	615,765	630,659	656,211	670,709	681,103	697,769
				KWH Per Customer				
Domestic	5,081	7,209	9,329	9,563	10,058	10,359	10,964	11,052
Commercial	16,417	21,615	29,285	30,455	32,815	33,567	35,803	37,918
				Energy Sales (Millions of KWH)				
Domestic	2,127	3,500	5,156	5,413	5,924	6,228	6,697	6,920
Irrigation	1	3	2	2	2	2	2	9
Commercial	842	1,215	1,720	1,833	2,054	2,173	2,342	2,512
Industrial	2,167	3,435	3,546	3,663	3,949	4,164	4,410	5,432
Other	250	317	397	420	452	487	528	568
Total	5,387	8,470	10,821	11,331	12,381	13,054	13,979	15,441
Energy Requirements	6,308	10,054	12,487	13,016	14,169	14,792	15,930	17,407
Losses	921	1,584	1,666	1,685	1,788	1,738	1,951	1,966
% Losses	14.6	15.8	13.3	12.9	12.6	11.7	12.2	11.3
December Peak (mw)	1,268	1,974	2,406	2,637	2,765	2,863	3,624	3,453

Source: FPC and BPA records.

SEASONAL CHARACTERISTICS

Table 2 shows the monthly distribution of peak and energy loads for 1960 and 1965, although neither distribution can be considered "typical" because monthly loads have not been adjusted for weather variations from normal. The data are sufficient to indicate a seasonal pattern characterized by low summer loads and a winter peak. The winter peak is created mostly by the predominance of electric space heating. This load is being aggressively promoted by the electric utilities in the Area and is growing rapidly due to favorable prices in relation to competitive fuels. The Area is generally characterized by cool summers and, as a result, there is very little summertime air conditioning load.

TABLE 2. Monthly peak and average loads for Puget Sound Area

	1960				1965			
	Peak Megawatts	Percent of Dec. Peak	Average Megawatts	Percent of Annual Average	Peak Megawatts	Percent of Dec. Peak	Average Megawatts	Percent of Annual Average
January	2,404	99.9	1,633	114.4	3,178	92.0	2,281	114.8
February	2,223	92.4	1,572	110.2	2,985	86.4	2,207	111.1
March	2,313	96.1	1,552	108.8	2,834	82.1	2,093	105.3
April	2,068	86.0	1,413	99.0	2,760	79.9	1,961	98.7
May	1,970	81.9	1,339	93.8	2,638	76.4	1,816	91.4
June	1,868	77.6	1,255	87.9	2,336	67.7	1,705	85.8
July	1,732	72.0	1,155	80.9	2,282	66.1	1,642	82.6
August	1,899	78.9	1,258	88.2	2,361	68.4	1,695	85.3
September	1,992	82.8	1,344	94.2	2,599	75.3	1,851	93.2
October	2,183	90.7	1,421	99.6	2,740	79.4	1,986	99.9
November	2,396	99.6	1,555	109.0	3,158	91.5	2,172	109.3
December	2,406	100.0	1,627	114.0	3,453	100.0	2,436	122.6
Annual	2,406		1,427		3,453		1,987	
Load Factor	59.3				57.5			

Source: FPC and BPA records.

PRESENT POWER DEVELOPMENT

HYDROELECTRIC

GENERAL DISCUSSION AND BACKGROUND

Electric power development began with an accidental discovery in Vienna, Austria, in the year 1873. The discovery was that a dynamo became a motor when electricity was fed to it from another dynamo. Thomas Edison and others, foreseeing a vast new field for electricity, immediately improved the dynamo and began connecting motors as well as lights to it rather than to a battery. New communities and industries in the west were ready and eager to put this new found source of light and power to work and by the time Edison opened his historically important Pearl Street station in New York City in 1882, hydroelectrical dynamos installed in 1881 were turning machinery and furnishing light in a smelter in Ketchum, Idaho.[1] The first water power plant in the Puget Sound Area was placed in operation on a small unnamed stream in the city of Tacoma in 1886.[2] Puget Sound Power & Light Company's Snoqualmie Falls No. 1 plant which has been operating since 1898 is the oldest operating plant in the Area.

The Puget Sound Area has maintained leadership in supplying low-cost power to rural and urban domestic customers as well as to industrial users from the beginning. In 1882, energy cost to customers in the United States was 25 cents per kilowatt-hour. It averaged 9 cents in 1912, 6 cents in 1930, 5 cents in 1935, and currently is 1.68 cents. In the Puget Sound Area the corresponding cost for 1882 was the same as the national average, but, the cost per kilowatt-hour was 7 cents in 1912, 2.83 cents in 1930, 2.7 cents in 1935, and currently is less than nine-tenths of a cent.[3]

Herbert A. Resner wrote in 1936, "No area in the United States offers more favorable opportunity for development of water power than the slopes of the Cascade and Olympic Mountain Ranges in Washington. The general elevation of these high ranges is from 3,000 to 8,000 feet above sea level, with four high glacial peaks from 10,000 to 14,000 feet in elevation. The streams draining these areas reach sea level in a comparatively short distance, making available the rapid fall essential for economic development of water power." At the close of 1936, 1,150,000 kw were installed in water power plants in the Pacific Northwest of which 401,346 kw were in the Puget Sound Area. Forecasters at that time foresaw an installed capacity of about 12 million kw for the Pacific Northwest by 1966. That estimate was a good one. Installations in the Columbia Basin and Puget Sound and coastal streams of Washington now amount to about 14 million kw. The forecasters were wrong with respect to the size and location of the installations, however, foreseeing much more development in the Puget Sound Area. Notwithstanding, the comparatively large size of the Bonneville and Grand Coulee powerhouses, one then recently completed and the other under construction, it was expected that water power developments of moderate capacity would be constructed in ever-increasing numbers. How far they were wrong is shown by comparison of the increase in power installations of 3.11 times for the Puget Sound Area with an increase of about 12 times in the same 30-year period for the Columbia Basin.

Advances in technology which permit the construction of plants of tremendous size using either water power, fossil-fuels, or atomic energy, have reduced unit production costs to such a degree that many otherwise potentially feasible water power sites in the Puget Sound Area are uneconomic. For this reason, and because of increasing values in the non-power resources of the streams, the rate of hydroelectric development within the Area is less than the rate for the Northwest as a whole. As cheaper power becomes available from various thermal sources it may be increasingly difficult to demonstrate feasibility for conventional water power projects whether large or small. Specialized water

[1] Idaho Department of Commerce, 1963.

[2] Columbia Basin Inter-Agency Committee, 1964.

[3] Federal Power Commission, 1964.

power plants such as those having access to large storage and pumped-storage developments appear to have a better future in the Puget Sound Area.

The Puget Sound Area was self-sufficient in power resources and supply until the outbreak of World War II. Importation of power began in the early 1940's and has increased until it now exceeds energy produced within the Area by more than three times. Energy importations are almost entirely from hydroelectric plants on the main stem of the Columbia River and current plans indicate that the trend will continue.

The rivers in the Puget Sound Area are arranged radially about Bellingham Bay, Samish Bay, Padilla Bay, Skagit Bay, Possession Sound, Puget Sound, and the Strait of Juan de Fuca. The Nooksack, Skagit, Stillaguamish, Snohomish (Skykomish, and Snoqualmie), Cedar, White, Puyallup, and Nisqually Rivers drain the western slopes of the Cascade Range between the Canadian border and Mount Rainier. The Deschutes River drains the northern slope of the low divide separating the Puget Sound and the Columbia River drainage basins west of the Cascade Mountains. The Skokomish, Hamma Hamma, Duckabush, Dosewallips, Dungeness, and Elwha Rivers drain the eastern and northern slopes of the Olympic Mountains. Converging as they do toward the settlements surrounding the protected harbors of the bays and sounds, these rivers have been a source of power and energy since the earliest days of settlement.

Eight of the basins have hydroelectric power developments and three have none. The accompanying tabulation shows the number of plants and total installed capacity in each basin:

Basin	No. of Plants	Installed Capacity
Nooksack-Sumas	1	1,500 kw
Skagit-Samish	8	776,800 kw
Snohomish	2	41,700 kw
Cedar-Green	1	22,900 kw
Puyallup	2	95,500 kw
Nisqually-Deschutes	4	123,800 kw
West Sound	2	124,200 kw
Elwha-Dungeness	2	24,000 kw
Total	22	1,210,400 kw

There are no existing hydroelectric power plants in the Stillaguamish Basin, the San Juan Islands, or Whidbey-Camano Islands. Developed hydroelectric sites are shown in Table 3 and Figure 1.

Seven organizations produce electric energy in the Puget Sound Area. There are—three municipally owned, one Federally owned, one private utility, and two industrial firms. The following tabulation shows the initial operating date, the present number of plants and the installed hydroelectric capacity for each producer in the Area.

Producer	Initial Operation[1]	No. of Plants	Installed Capacity-kw
Municipal utilities			
Tacoma Department of Public Utilities	1893	4	238,200
Seattle Department of Lighting	1904	5	639,300
City of Centralia prior to	1930	1	9,000
Federal producers			
National Park Service	1923	1	800
Private utilities			
Puget Sound Power & Light Co.	1898	7	297,100
Industrial firms			
Lone Star Cement Co.	1907	2	2,000
Crown Zellerbach Co.	1911	2	24,000
Total		22	1,210,400

[1] By present owner or predecessor.

FIGURE 1. Developed hydroelectric and thermal-electric power plants in the Puget Sound Area.

TABLE 3. Developed hydroelectric power plants in the Puget Sound Area

Plant	Owner	River	Mile	Initial Operation	Installed Capacity kw	Average Annual[1] Output (MWH)	Usable Storage (acre-feet)	Gross Head (feet)
Nooksack	PSPL	Nooksack	70	1906	1,500	5,000	--	195
Lower Baker	PSPL	Baker	1	1925	64,000	381,000	142,000	259
Bear Creek No. 1	LSC	Bear Creek	0.2	1908	1,800	13,000	--	422
Bear Creek No. 2	LSC	Bear Creek	0.2	1925	200	1,000	--	72
Upper Baker	PSPL	Baker	9	1959	94,400	336,000	221,000	285
Newhalem[2]	S	Newhalem Creek	0.3	1921	2,000	8,000	--	507
Gorge	S	Skagit	94.5	1924	134,400	915,000	7,000	380
Diablo	S	Skagit	98.7	1936	120,000[3]	778,000	61,000	330
Ross	S	Skagit	102.7	1952	360,000	688,000	1,023,000	398
Snoqualmie No. 2	PSPL	Snoqualmie	35.6	1910	30,100	204,000	--	287
Snoqualmie No. 1	PSPL	Snoqualmie	36.1	1898	11,600	70,000	--	257[4]
Cedar Falls	S	Cedar	82.8	1904	22,900	97,000	62,000	625
White River	PSPL	White	40	1912	70,000	322,000	44,000	489
Electron	PSPL	Puyallup	42	1904	25,500	172,000	--	871
Yelm	C	Nisqually	10	1930	9,000	89,000	--	208
LaGrande	T	Nisqually	31.8	1912	64,000	372,000	--	419
Alder	T	Nisqually	35	1945	50,000	248,000	180,000	273
Paradise[5]	NPS	Paradise	0.3	1923	800	2,000	--	486
Cushman No. 2	T	N.F. Skokomish	9	1930	81,000	302,000	2,000	480
Cushman No. 1	T	N.F. Skokomish	11	1926	43,200	157,000	372,000	255
Elwha	CZ	Elwha	5	1911	12,000	65,000	3,000	104
Glines Canyon	CZ	Elwha	14	1927	12,000	99,000	26,000	192
Total 22					1,210,400	5,324,000	2,143,000	

PSPL – Puget Sound Power & Light Co.
LSC – Lone Star Cement Corp.
S – Seattle Department of Lighting (Seattle City Light)
C – City of Centralia
T – Tacoma Department of Public Utilities (Tacoma City Light)
NPS – National Park Service
CZ – Crown Zellerbach

[1] Median month flows—estimated average annual potential with present capacity or amount reported by operator.

[2] Damaged by fire in July 1966. Repair is underway.

[3] Excluding two 1,200 kw auxiliary units.

[4] For units No.'s 1-4; 271 feet for unit No. 5.

[5] Sometimes called Longmire.

EXISTING HYDROELECTRIC DEVELOPMENT

NOOKSACK-SUMAS BASINS

Nooksack—this power plant (sometimes called the Excelsior plant) owned by Puget Sound Power & Light Co. is on the right bank of the Nooksack River about a half mile downstream from Nooksack Falls in Whatcom County. The diversion dam, upstream from the falls, consists of planks resting on a concrete toe. The intake works are approximately 2,622 feet long and are made up of a 467-foot concrete flume, a 566-foot long wood-stave pipe, a 1,025-foot long 8-foot diameter unlined tunnel, and a 564-foot steel penstock varying in diameter from six to five feet. The turbine is a 2,547 horsepower wheel connected

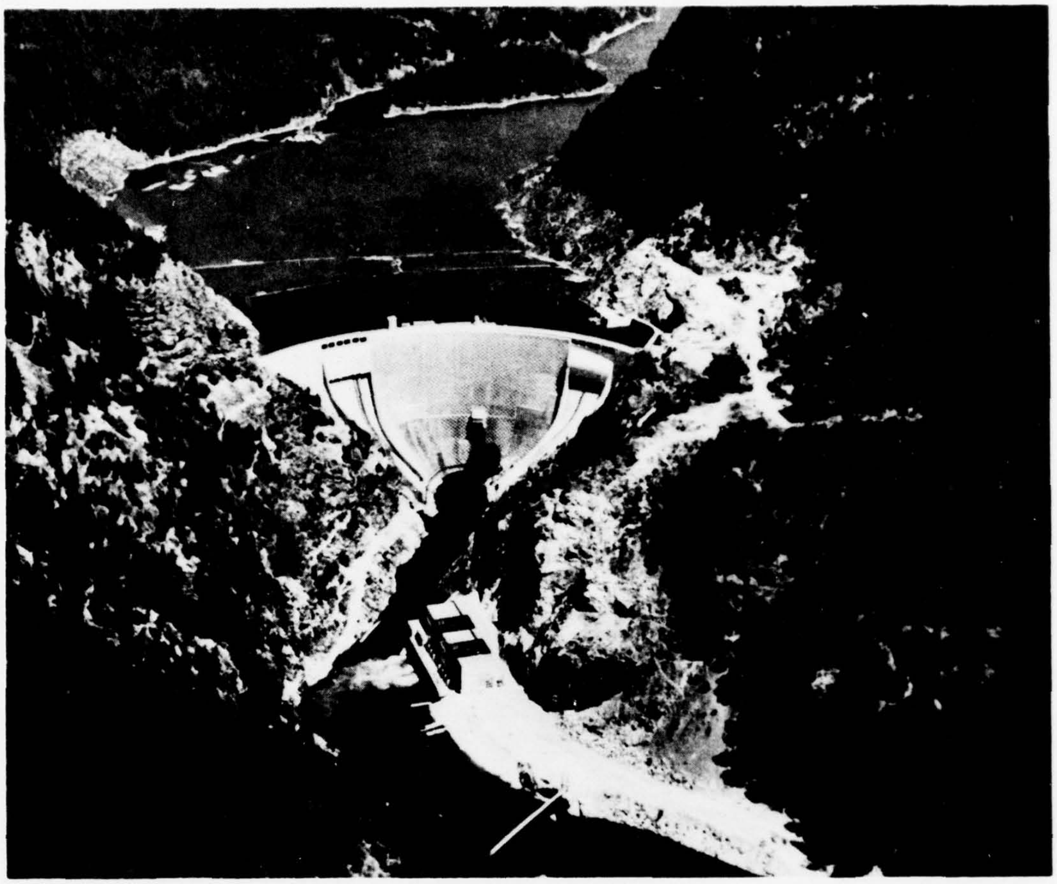


PHOTO 1. Ross Dam, Skagit River—Seattle City Light Photograph.

horizontally to a three-phase 60-cycle, 1,500 kw generator.

SKAGIT-SAMISH BASINS

Ross project of Seattle City Light is the largest hydroelectric power development in the Puget Sound Area. Ross Dam, which was constructed in two stages and may be raised an additional 125 feet, is a spectacular concrete arch which exhibits a honeycomb downstream face with a ski-jump spillway at each end. The purpose of the waffle-like construction is to provide for future enlarging of the dam. If the dam is raised another 125 feet, increasing the maximum pool elevation from its present 1,600 feet to 1,725 feet above sea level as contemplated, additional concrete will be interlocked with the five-foot square depressions to thicken the base. The first construction stage was undertaken in 1937 and completed in 1940, at which time the dam was 305

feet high. Work began on the second stage in 1943 and was completed in 1949. The dam is 540 feet high, 1,300 feet long, and contains 909,000 cubic yards of concrete. The gross storage capacity of the reservoir is 1,405,000 acre-feet. From December 1 to March 1 a flood control space of at least 120,000 acre-feet is provided. This flood control storage has been used beneficially on a number of occasions since 1949. Complete closing of the power plant has been necessary several times in order to hold back the flood waters. Six radial spillway gates 20 feet by 19.5 feet control each of the two spillways. The gates were installed in 1953.

The reservoir, Ross Lake, has a total length of 24 miles and extends 1.5 miles into Canada. It has an area of 11,820 acres. The powerhouse is located on the left bank of the Skagit River a short distance downstream from the dam. The power plant units were installed in 1952, 1953, 1954, and 1956, respectively. Two power tunnels, each 27.5 feet in diameter, finished to 24.5 feet with concrete lining, carry the water 1,900 feet to the turbines, which are of the Francis type. They are each rated at 140,000 horsepower at 150 rpm under the ultimate average head of 440 feet. Under the present 355-foot average head, each is rated at 120,000 horsepower. Each generator has a nameplate rating of 90,000 kw, giving a total installation of 360,000 kw.

Diablo plant, the second unit of the Seattle City Light Skagit River project was begun in 1927. The dam was finished in 1929. Diablo is an arch dam with a structural height of 389 feet and a crest length of 1,180 feet. The dam is 146 feet thick at the base. Two 15-foot diameter penstocks 290 feet long and 19.5 diameter tunnel 2,000 feet long carry the water to the powerhouse on Reflector Bar. The first generating unit with an installed capacity of 60,000 kw was installed in 1936, and a second 60,000 kw

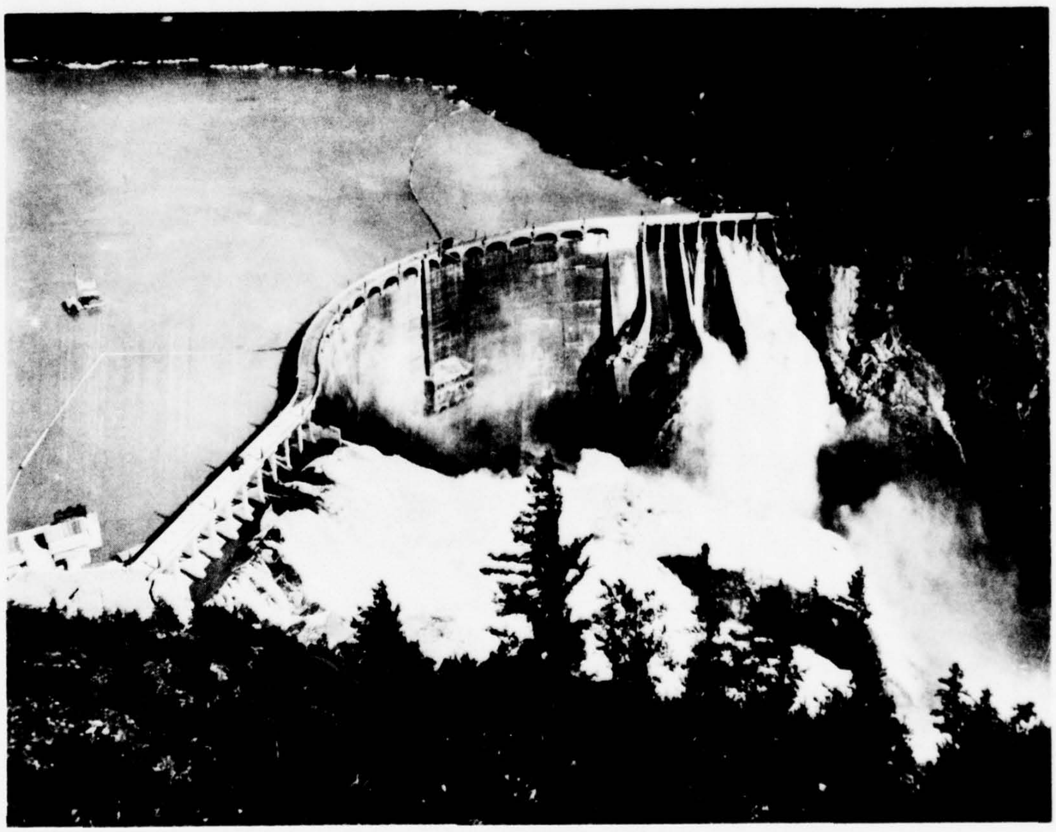


PHOTO 2. Diablo Dam, Skagit River—Seattle City Light Photograph.

unit was placed in operation in 1937. The turbines are of the vertical-shaft Francis type. Renovation and rebuilding was accomplished on these units in 1958. At the time of its construction the Diablo power plant contained the largest capacity water wheel ever built except for the Hoover power plant on the Colorado River, which includes 155,000 kw units.

The U.S. Government retains the right to use water as may be necessary for navigation from both the Ross and Diablo dams.

The **Gorge** plant, placed on the line in 1924 has been termed the first major unit of the Skagit River power development by Seattle City Light. Two generators with a capacity of 24,000 kw each were installed in 1924, a 26,400 kw generator was placed in operation in 1929, and a 60,000 kw generating set was installed in the plant in 1951, giving a total installation of 134,400 kw for this plant. The 1924 sets were rebuilt in 1959, the 1929 sets were rebuilt in 1961, and the 1951 installations were rebuilt in 1960. The present dam, Gorge high dam, was completed and all power plant units were connected to the new intakes in 1961. A two-mile long 20.5-foot diameter tunnel carries the water to the power plant.

Newhalem on Newhalem Creek, is the original Skagit River Development by Seattle City Light. This plant of 2,000 kw was built in 1921 to provide energy for driving the power tunnel for the Gorge development. The plant obtains its water from Newhalem Creek and the plant tailwater discharges into Skagit River about half a mile downstream from Gorge powerhouse. The plant is connected to Seattle's distribution system. Water is diverted by a timber dam into an unlined tunnel 2,689 feet long. A steel penstock 33 to 30 inches in diameter and 905

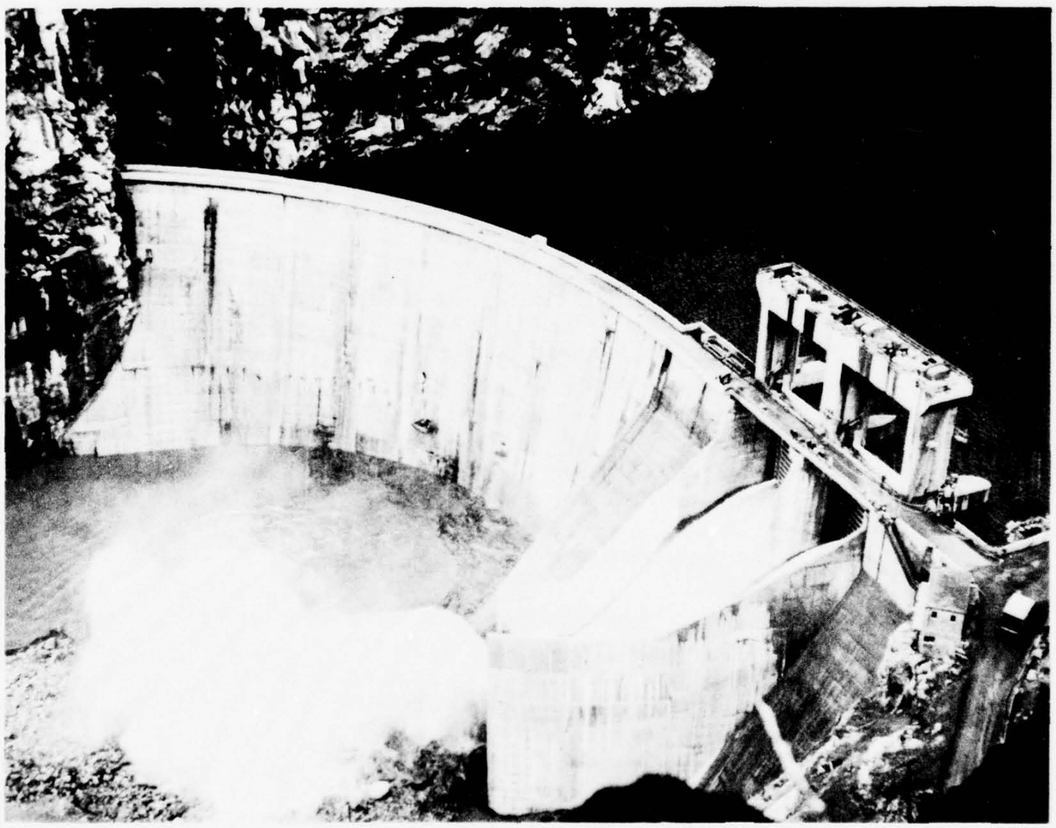


PHOTO 3. Gorge Dam, Skagit River–Seattle City Light Photograph.

feet long delivers the water to the powerhouse. A double-overhung Pelton turbine drives the 2,000 kw generator. A fire damaged this plant on July 16, 1966, and it is temporarily out of operation. Repair of the plant is underway and expected to be completed by December 1969.

Upper Baker Dam of Puget Sound Power & Light Co. on Baker River was completed in 1959. The dam is concrete gravity type, 330 feet high, 1,235 feet long, and has a crest width of 12 feet. This project has an installed capacity of 94,400 kw. Baker Lake has a gross storage capacity of 298,000 acre-feet, of which 220,000 acre-feet are usable.

The Federal Power Commission license requires 16,000 acre-feet of flood control storage to replace the valley storage eliminated by the project. An additional 84,000 acre-feet of storage may be utilized for flood control, provided that suitable arrangements are made by the Corps of Engineers to compensate the licensee. The project includes facilities for the protection of fish and wildlife, such as ladders, traps, hatcheries and other devices.

The area of Baker Lake at normal full pool is 4,985 acres, and the water backs nine miles upstream from the dam. An earthfill dam in a nearby saddle is 115 feet high, 1,200 feet long and has a fill volume of 454,000 cubic yards.

Bear Creek No. 1 plant of the Lone Star Cement Corporation is on Bear Creek, a tributary to Baker River. The dam is a concrete arch rising 22 feet above the foundation. It is 217 feet long, 20 feet thick at the base, 3 feet thick at the crest, and contains 1,080 cubic yards of concrete. The spillway is 80 feet wide and the reservoir is controlled by flashboards. The reservoir is a quarter of a mile long and has about one mile of shoreline. A 36-inch diameter wood and steel penstock 1,800 feet long delivers the water to the powerhouse. The three horizontal shaft Pelton turbines, designed for a speed of 450 rpm, went into operation in 1980. The installed capacity of the plant is 1,800 kw.

The **Bear Creek No. 2** plant of Lone Star Cement Corporation is downstream from Bear Creek No. 1. An earthfill dam five feet above the riverbed is 33 feet long, 6 feet thick at the base, and 3 feet at the crest. A 36-inch wood penstock 400 feet long delivers the water to the horizontal shaft turbine designed for a speed of 450 rpm. This project, with an installed capacity of 200 kw, went into initial operation in 1925.

The **Lower Baker** development of Puget Sound Power & Light Co. on Baker River was placed in operation in 1925. The plant originally contained two main generating units and a 450 kw auxiliary generator. Generator No. 1 was rebuilt in 1953 and generator No. 2 in 1954. Their present nameplate capacity is 19,750 kw each. A third generating set with a nameplate rating of 64,000 kw was placed in the plant in 1960. Lower Baker Dam is a concrete gravity arch 285 feet high and 530 feet long. Lower Baker Reservoir, Lake Shannon, has a surface area of 2,218 acres and backs water 9.5 miles to Upper Baker Dam. The powerhouse was destroyed by mud and rockslide on May 18, 1965, and was rebuilt with only the 64,000 kw unit No. 3 back on the line on September 1, 1968. There are no plans for reconstructing units No. 1 and 2.

SNOHOMISH BASIN

The only water power plants in the Snohomish Basin are the **Snoqualmie Falls No. 1 and 2** plants of Puget Sound Power & Light Co. The first generating facilities were constructed in 1898 on the left (westerly) bank of the river at Snoqualmie Falls. These facilities were patterned after the Niagara Falls project and the four 1,500 kw generating units were placed in a cavern hollowed out of basalt 268 feet underground. A fifth generating unit with a capacity of 5,600 kw was added in 1905, raising the total installed capacity of the Snoqualmie Falls No. 1 plant to 11,600 kw.

Snoqualmie Falls No. 2 power plant was built in 1910 about half a mile downstream from the falls on the north (right) bank of the river. Originally, it contained one 9,000 kw-capacity generating unit which was rewound in 1962, raising its nameplate rating to 9,840 kw. A second generating set rated at 20,250 kw was added in 1957, giving a total installation of 30,090 kw for this plant. Both power plants divert water above Snoqualmie Falls by means of a 5-foot high, 12-foot wide, and 200-foot long concrete slab that forms the crest of the falls. Figure 2 is a schematic representation of these power plants.

Snoqualmie Falls has a drop of 268 feet, about 100 feet greater than Niagara Falls, and is one of Washington's favorite scenic spots. Indians traveling through the mountains to the Puget Sound fishing ground used the area as a campsite, building their camp and council fires on the edge of the cataract. The name "Snoqualmie" is derived from the Indian "Sdoh-kwahl-bu" meaning "Moon People."

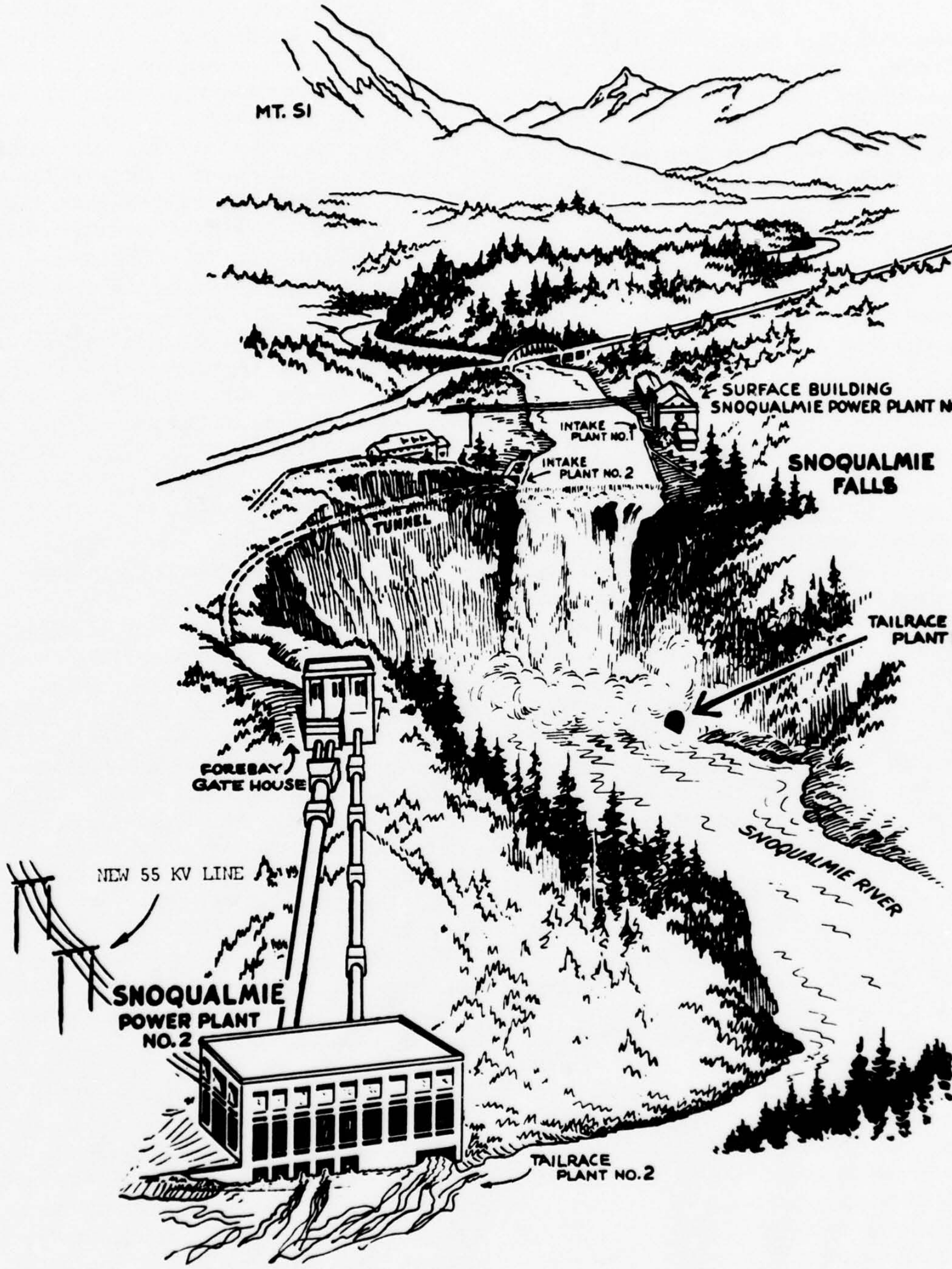


FIGURE 2. Snoqualmie Falls hydroelectric development—Puget Sound Power and Light Co. Drawing.

CEDAR-GREEN BASINS

Cedar Falls Dam is owned by Seattle City Light. In 1902, Seattle citizens voted to build a city-owned light plant and work was begun on a crib dam at Cedar Falls. The first residential customers were served in 1905 with power from two 1,200 kw hydroelectric units installed the year before at Cedar Falls. In 1912, work was begun on the Cedar Falls masonry dam and in 1914 it was completed. The first generator was installed in the new powerhouse in 1921 and the second in 1929. The nameplate rating of each generator is 11,428 kw, giving a total installed plant capacity of about 22,900 kw.

PUYALLUP BASIN

Electron hydroelectric project is located on Puyallup River near Kapowsin, Pierce County, 23 miles southeast of Tacoma. The diversion dam is 14 river miles upstream from the powerhouse. The diversion dam, flume, and powerhouse with four 6,000 kw generating units were placed in operation on April 14, 1904. A new timber apron and concrete pier anchorage were added to the diversion dam in 1910. One of the original units was destroyed by lightning in June 1928, and was replaced with a 7,500 kw machine in April 1929. In November 1936 all of the generators were put out of service by a slide. Two units were put back in service in July 1938 and the entire station was returned to operation in December 1941. The diversion dam creates a reservoir having a capacity of 120 acre-feet of water. The diversion is at an elevation of about 1,620 feet above sea level and a 10.1-mile long flume follows the left bank of Puyallup River to the forebay. The forebay at the downstream end of the flume supplies water to four horizontal wood stave penstocks which change to steel at the brow of the hill and supply water to the main generating units. A smaller penstock supplies water for two exciter units. The turbines are of the twin impulse type, three developing 7,500 horsepower and one developing 10,000 horsepower. Three generators are 6,000 kw each and the fourth is 7,500 kw, giving a total plant installation of 25,500 kw.

White River hydroelectric project is on White River two miles north of Sumner, and six miles south of Auburn. The White River above the project drains the northeast slopes of Mount Rainier. The plant was completed originally in 1911 and was increased by rewinding in 1917. Additional units were installed in 1918 and 1924 and the capacities of these latter units were increased by rewinding in 1952 and 1956 resulting in a total installed capacity of 70,000 kw. A low timber diversion dam near Buckley diverts the water into a series of flumes and canals 14 miles long to Lake Tapps Reservoir. Four Francis type horizontal shaft turbines, two rated at 18,000 horsepower and two at 23,000 horsepower, at the design head of 440 feet, are connected by horizontal shafts to the generators. To insure that the important fishery resources of White River are not unduly impaired, the migrant fish are trapped and carried to Mud Mountain dam, and small fish are guided past Lake Tapps Reservoir by means of a fish screen and by-pass pipe. Lake Tapps Reservoir originally consisted of Lake Tapps, Lake Kirtley, Lake Crawford, and Church Lake. A series of dams with a total length of 2.5 miles raise the water 35 feet above the original elevation into one large lake with a surface area of 2,566 acres and a capacity of 46,655 acre-feet.

NISQUALLY-DESCHUTES BASINS

Paradise hydroelectric power plant sometimes called Longmire owned by the National Park Service was completed in 1923. Water for the plant is diverted and carried about one mile along the right bank of Paradise River to the power plant. The plant, with an installed capacity of 800 kw, furnishes power for lights and small equipment.

Alder Dam completed in 1945, is a concrete arch 285 feet above the riverbed and 330 feet above bedrock. It is located on the Nisqually River. The dam has a crest length of 1,600 feet, is 120 feet thick at the base, 15 feet thick at the top, and contains 420,000 cubic yards of concrete. The spillway is situated on the left abutment and the water level is controlled by four Tainter gates with a combined length of 128 feet. Alder Reservoir is seven miles long, has 28 miles of shoreline, covers 3,065 acres, and has a storage capacity of 232,000 acre-feet. The maximum and minimum pool elevations are 1,207 and 1,114 feet above sea level, respectively. Two penstocks, 10 feet in diameter and 160 feet long, carry the water to the seven-story, reinforced concrete powerhouse. The two 25,000 kilowatt generators, were both installed in 1945. The vertical shaft Francis turbines are each rated at 34,500 horsepower at 225 rpm.

The **LaGrande** project on the Nisqually River was first placed in operation in 1912. The present

dam was completed in 1945. It is a concrete-gravity structure 212 feet above bedrock. The dam's crest length is 710 feet, its thickness is 85 feet at the base and 14 feet at the top, and the volume of concrete is 85,000 cubic yards. The reservoir is small; 1.5 miles long, 3.5 miles of shoreline, 45 acres of surface, and 2,700 acre-feet of water. The reservoir is regulated between a maximum elevation of 935 feet and a minimum of 910 feet above sea level. A diversion tunnel 6,400 feet long and 14.5 feet in diameter, and four 4-foot diameter and one 11.5-foot diameter steel penstocks 120 feet long deliver the water to the powerhouse. The first four generating sets were installed in 1912. The turbines for these sets are horizontal shaft, fixed blade, and rated at 8,000 horsepower at 450 rpm. The generators in these sets are rated at 6,000 kw each. Unit No. 5, added in 1945, is a vertical shaft fixed blade Francis wheel rated at 54,000 horsepower at 257 rpm. It is connected to a generator with a nameplate rating of 40,000 kw. This unit was added in 1945 in conjunction with the construction of Alder Dam just upstream. LaGrande was also partially reconstructed at that time.

Yelm plant was constructed by the city of Centralia on the Nisqually River in 1930. Prior to the completion of this plant, the city has purchased power from the Western Crossarm and Manufacturing Company. Head for the Yelm plant is developed by means of a diversion dam and a 9-mile canal to the powerhouse site. The dam is a rock-filled timber crib with a concrete cap. Its height is 8 feet. Initially, the plant contained two 2,000 kw generating units. A third unit with a generating capacity of 5,000 kw was added in 1955, for a total plant capacity of 9,000 kw. The turbines are vertical shaft and of the Francis type.

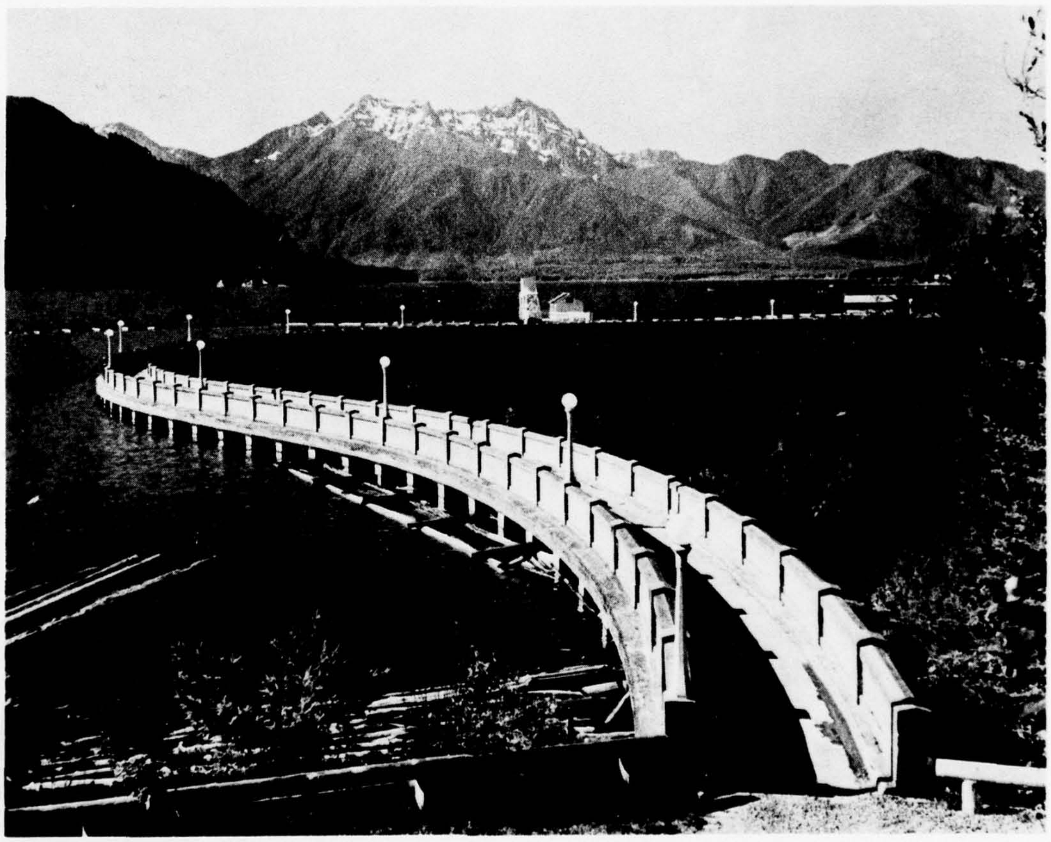


PHOTO 4. Cushman No. 1 Dam, North Fork Skokomish River—Tacoma City Light Photograph.

WEST SOUND BASINS

Cushman No. 1 dam and power plant was completed in 1926 on the North Fork Skokomish River *in the West Sound subregion. Cushman Dam* is a concrete arch 235 feet above riverbed and 275 feet above bedrock. The crest length is 1,111 feet and the spillway is 200 feet wide. The dam is 50 feet thick at the base, 8 feet thick at the top, and contains 90,000 cubic yards of concrete. The reservoir has a length of 9.6 miles and an area of 4,200 acres. Its storage capacity is 453,350 acre-feet. Maximum and minimum pool elevations for power operations are 738 feet and 615 feet above sea level. The power plant contains two generators with a nameplate rating of 21,600 kw each. The turbines are Francis type, each rated at 25,000 horsepower at 200 rpm. Water is carried to the powerhouse through a 17-foot diameter by 540-foot long tunnel on the left bank of the river. Both penstocks are steel, 10 feet in diameter and 150 feet long.

Cushman No. 2 power plant is located on Hood Canal and was placed in service in 1930. A concrete arch dam on the North Fork Skokomish River, and a 2.5-mile long by 17-foot diameter tunnel and three 10.5-foot diameter by 1,350-foot long penstocks deliver the water to the generating sets. Cushman No. 2 Dam is 175 feet above the riverbed and 235 feet above bedrock. Crest length is 460 feet, thickness is 40 feet at the base and 8 feet at the top, and volume of concrete is 38,000 cubic yards. The spillway is 120 feet wide and the lake level is controlled by three caterpillar gates. The reservoir has a storage capacity of 8,000 acre-feet at maximum elevation 480 feet above sea level. It is two miles long, and has 4.5 miles of shoreline. The powerhouse contains three generating units. These have Francis vertical shaft turbines each rated at 37,500 horsepower at 300 rpm, and

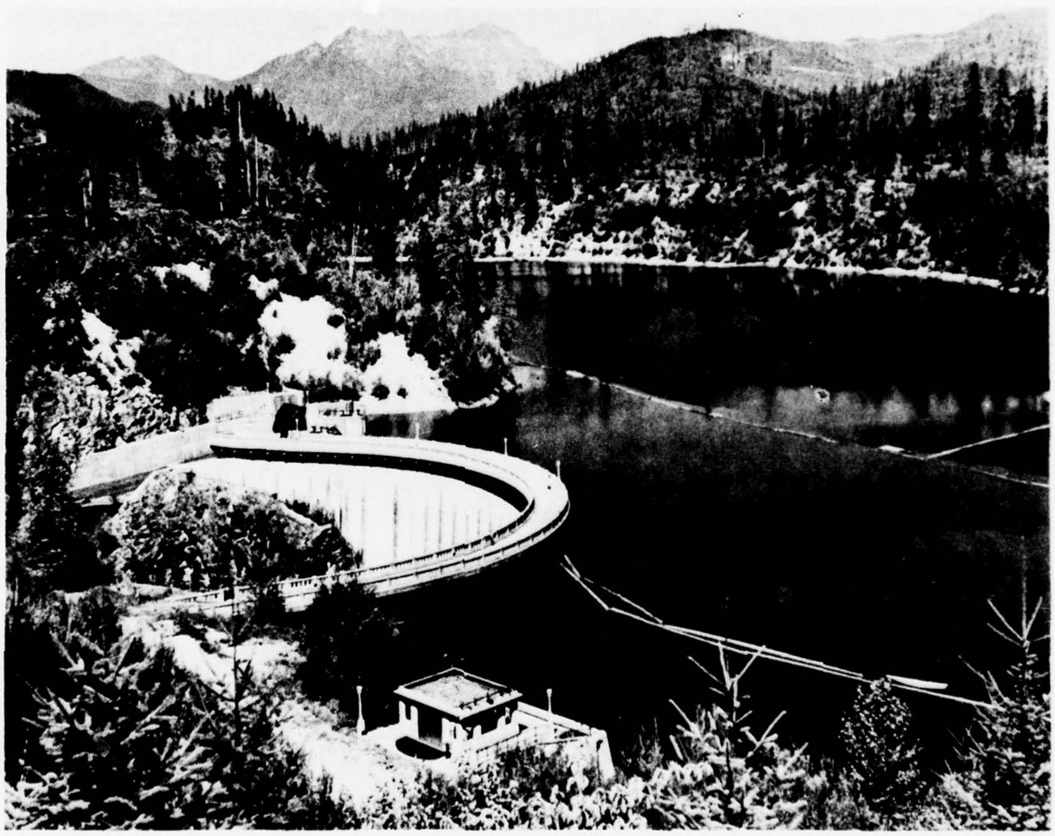


PHOTO 5. Cushman No. 2 Dam, North Fork Skokomish River—Tacoma City Light Photograph.

generators rated at 27,000 kw each. Two of them were installed in 1930 and the third in 1952.

ELWHA-DUNGENESS BASINS

Elwha plant on the Elwha River is owned by Crown Zellerbach Corporation. This plant was placed in service in 1911 and has four generating units, two with horizontal shafts and two with vertical shafts, for a total installed capacity of 12,000 kw. It operates under a gross head of 104 feet. The dam is a concrete gravity structure which creates a reservoir (Lake Aldwell) having a usable storage of 3,000 acre-feet and about 320 acres of surface area. The reservoir has a normal pool elevation of 188 feet. The power plant is shown on the Elwha 7-1/2 minute topographic quadrangle, 1950, as the Olympic power plant.

Glines Canyon plant, also on the Elwha River and owned by Crown Zellerbach Corporation, is upstream from the Elwha plant. The plant, built in 1927, is located a short distance downstream from the reservoir, Lake Mills, inside Olympic National Park. Lake Mills has a total usable storage of 26,000 acre-feet with a surface area of 435 acres at a normal pool elevation of 608 feet. The plant has a single generating unit with a nameplate rating of 12,000 kw.

THERMAL—ELECTRIC AND OTHER

There are seven thermal-electric generating plants in the Puget Sound Study Area operated by four electric utility systems. Three of the systems are public-non-Federally owned, and the other privately-owned. The locations of these thermal-electric sources are shown on Figure 1.

The capacity installed in these utility system plants totals 202,310 kw, of which 200,000 kw are located in five fossil-fuel steam-electric plants. The remaining 2,310 kw are in two Diesel-electric plants. The names of these plants and important installation details are given in Tables 4 and 5.

There are in the Puget Sound Area, in addition to electric generating capacity in utility plants, a number of relatively small plants owned by the industries. Their generation is used principally for processing lumber and food products. Other non-utility generating capacity is located at military installations. Of this, the largest installation is at the Bremerton Naval Ship Yard with 18,000 kw. Any of the energy produced by these sources which enters the Area's transmission system does so usually on a non-firm basis. For this reason these plants have not been included as a part of the power production resources dedicated to supply the Area's electric customers.

No new thermal-electric installations have been made since 1954. In that year a 25,000 kw unit was placed in operation by the city of Tacoma. All other steam plant units were installed prior to 1932. The oldest unit, 3,000 kw, is the Georgetown plant of the city of Seattle. This plant was placed in operation in 1907. The largest units in this system of thermal-electric sources are twins, each rated at 43,750 kw. They were installed in 1929 and 1930 in the Puget Sound Power & Light Company's Shuffleton plant. The Diesel units operated by Orcas Power & Light Co. were installed at various times from 1938 through 1949.

The thermal-electric plants are located on Lake Union and Lake Washington, the Duwamish River, and directly on Puget Sound or its channels. Because of their locations, the availability of water for condenser, engine cooling, and boiler make up is unlimited. Table 4 also gives types of cooling water systems and the minimum water requirements for each plant.

These plants are fueled by various grades of oil ranging from Bunker "C" and PS 400 to light Diesel. Deliveries are made by truck and barge.

Some of the important operational characteristics of these thermal-electric plants are given in Table 5. As indicated, they are held as stand by or intermittent use capacity. Their capability, when in operation, may exceed or fall below their nameplate ratings. Also of interest are net capabilities of these plants with all equipment in service, and with the largest generator and/or boiler out of service. Their net heat rates are indicative of their thermal efficiencies. Because of the relative small sizes of the units, their temperature and pressure ratings are necessarily of a moderate scale. Only with high temperature reheat and pressure systems can heat rates approach the low level required to provide for low-cost power production.

The thermal-electric plant units are rarely called

TABLE 4. Existing thermal-electric and Diesel-electric generating plants, Puget Sound Area as of December 31, 1965

Owner	Type Ownership	Plant Name	Location	River Basin Subregion	Installation Date of Units & Capacity: Unit No.	Year	KW	Total Installed Capacity KW	Source Cooling Water Type of Cooling Min. Available	No. of Boilers	Type of Fuel
Seattle, city of Dept. of Lighting	Municipal	Lake Union	Seattle	Cedar	11	1914	7,500	30,000	Lake Union	14	Oil
					12	1918	10,000		Flowthrough		
					13	1921	12,500		80cfs		
	Municipal	Georgetown	Seattle	Green	1	1907	3,000	21,000	Duwamish River	16	Oil
					2	1908	8,000		Jet		
					3	1917	10,000		30 cfs		
Tacoma	Municipal	Steam Plant No. 1	Tacoma	White-Puyallup	1	1922	6,000	9,000	Puget Sound	2	Oil
					2	1922	3,000		Surface		
									Unlimited		
	Municipal	Steam Plant No. 2	Tacoma	White-Puyallup	1	1931	25,000	50,000	Puget Sound	2	Oil and/
									Surface		or coal
					2	1954	25,000		Unlimited		
Puget Sound Power & Light Co.	Private	Shuffleton	Renton	Cedar	1	1929	43,750	90,000	Lake Washington	3	Oil
					2	1930	43,750		Surface		
					3 (Aux.)	1929	2,500		133.6 cfs		
Orcas Power & Light Co.	Cooperative	Friday Harbor	San Juan Is.	San Juan Is.	1	1949	220	1,060	San Juan	0	Diesel
					2	1949	220		Channel		
					3	1949	220		Unlimited		
					4	1941	200				
					5	1946	200				
	Cooperative	East Sound	Orcas Island	San Juan Is.	1	1948	500	1,250	East Sound	0	Diesel
					2	1948	500		Unlimited		
					3	1938	100				
					4	1940	100				
					5	1938	50				
					Total Installed Capacity			202,310			

TABLE 5. Operational characteristics of existing thermal-electric and Diesel-electric generating plants, Puget Sound Area as of December 31, 1965

Plant Name	Installed Capacity Maximum Nameplate kw	Dependable Capacity On Peak kw	Plant Net Capability-Kilowatts: All Equip. in Service 2 Hrs.	All Equip. in Service Continuous	Largest Gen. Out 2 Hrs.	Largest Gen. Out Continuous	Largest Boiler Out 2 Hrs.	Largest Boiler Out Continuous	Net Heat Rate BTU Per KWH ½ Load	¾ Load	Full Load
Lake Union	(s) 30,000	--	40,000	30,000	23,333	17,500	40,000	30,000	23,483	21,792	27,019
Georgetown	(s) 21,000	--	21,000	16,000	9,000	9,000	21,000	16,000	--	--	--
Seattle-Total	(s) 51,000	(s) 46,000									
Steam Plant No. 1	(s) 9,000	--	9,500	9,000	3,200	3,000	6,400	6,000	--	--	20,000
Steam Plant No. 2	(s) 50,000	--	55,000	52,000	30,000	27,000	27,000	26,000	15,100	14,800	14,000
Tacoma-Total	(s) 59,000	(s) 61,000									
PSP&L–Shuffleton	(s) 90,000	(s) 85,800	85,800	80,000	43,000	43,000	60,000	60,000	15,307	16,314	15,197
Friday Harbor	(I) 1,060	--	1,060	--	840	--	N.B.	N.B.	--	--	--
East Sound	(I) 1,250	--	1,250	--	750	--	N.B.	N.B.	--	--	--
Orcas-Total	(I) 2,310	(I) 2,310									
Total Fossil-Fuel	202,310	195,110	187,000								

Normal use made of plant:

(s) Standby
(I) Intermittent
N.B. No boilers, plant is diesel engine
-- Not reported.

upon to supply energy. They occasionally are used to supply emergency power or short-time peaking requirements. Loading of the generating units depends largely on the condition of the boilers and operational costs at the time. Some units are tested every four months. The importance of regular testing is to determine the adequacy of the furnaces and ability of the steam boilers and auxiliaries to provide turbine steam. Test runs in these instances are usually for two hours. As a general rule, over the past years, most of the units are kept in a cold stand by condition. In those cases where boilers are under fire and are producing steam for industrial or space heating purposes, it is possible to divert the steam to the turbines and bring them to load condition in an hour or so. Eight or more hours are generally needed to bring up any of the plants or individual units to full load carrying capability. A considerable period of time prior to that would be needed to assemble a full crew at each plant if it was the decision to operate many of the plants for long periods or on a daily schedule. The economics of operating many of the older units and putting whole plants in condition to meet daily loads versus costs of alternative means to supply the increasing power requirements of the Area would need to be investigated.

POWER INTERCHANGES

The electric power loads for previous years up to 1965 in the Puget Sound Area were discussed in the section, "Historical Growth in Power Requirements" in the Introduction. The present development of hydroelectric and fossil-fuel electric (thermal and internal combustion) has also been presented. A comparison of these loads and resources follows:

1965 Peak Loads, Energy Loads
and Energy Resources
for the Puget Sound Study Area

	Peak MW	Energy Million KWH
Loads[1]	3,453	17,407
Resources		
Hydro[2]	(1,210)	(5,324)
Fossil-fuel[3]	(195)	(171[4])
Imports	2,048	11,912

[1] Table 1.

[2] Table 3.

[3] Table 5.

[4] Estimated 10 percent plant factor for existing fossil-fuel electric plants (195,000 kw x 8,760 hrs. x .10 = 171 x 10^6 kwh).

This illustration indicates that in 1965 there were additional supply requirements of 2,048 mw for peaking and 11,912 million kwh for energy. The Area is far from self-sufficient in power resources from presently installed hydro and fossil-fuel, since it meets about one-third of the average energy load. It is a large "importer" of electric energy from the rest of the Pacific Northwest power system, principally from plants in the Columbia River Basin. Therefore, interchanges take place on a coordinated basis through a number of interconnected systems in the Pacific Northwest. The high-voltage transmission lines of Bonneville Power Administration serve as the backbone grid of this huge electric power network. This system reinforces interchanges of power with Canada and with systems to the south and east.

A good example of the utilization of the Bonneville high-voltage network for power interchanges is the city of Seattle Department of Lighting (Seattle City Light). Seattle City Light has long-term purchase contracts with Pend Oreille County PUD for part of the output of Box Canyon Dam in northeastern Washington. It also has contracts with Grant County PUD to receive a percentage of the output from the Priest Rapids and Wanapum power plants. The power from these plants and its own plant, Boundary, on the Pend Oreille River in northeastern Washington is transmitted to the Seattle City Light service area through the use of the Bonneville grid.

TRANSMISSION FACILITIES

The electric high-voltage system of the Puget Sound Area shown on Figure 3 is made up of the present main grid and secondary transmission lines and those which will be in service by 1970. Not shown are a number of sub-transmission and distribution lines of 115 kv and lower voltages. These lines represent a total of 2,575 circuit miles and a land use of 31,840 acres. The line miles and the land required by the line rights-of-way are indicated by voltage level in Table 6.

Most of the main grid lines are of 230 kv. However, the major share of recent as well as future transmission lines are and will be designed for higher voltages. This is evidenced by the 287, 345, and 500 kv lines included in the tabulations. A 500 kv line, while costing approximately twice as much as a 230 kv line, has 4-5 times the transmission capacity, and requires only a little more right-of-way, thus reducing unit costs as well as land required per kilowatt of power transmitted. With other land use considerations becoming increasingly important, the new extra-high voltage (EHV) technology will help to limit the number of transmission lines needed to deliver electric power to the load centers.

The Puget Sound Area is and will continue to be a major load center in the Pacific Northwest. Local generation being much less than that required to satisfy the electric power needs of the Area, the major share, approximately 65 percent, of the Area's power requirements is transmitted from generating plants east of the Cascade Range. This is indicated by the number of east-west transmission lines shown on Figure 3.

There are also interregional interconnections to the north and south, to British Columbia and the Lower Columbia areas. The remainder of the main grid system interconnects regional generation and load centers.

Some of the 230 kv lines shown will probably be replaced by 500 kv or higher voltage lines, thus increasing the transmission capacity into the Area substantially while utilizing the same rights-of-way.

TABLE 6. Puget Sound Area transmission lines, circuit miles and land use by voltage level—October 1970

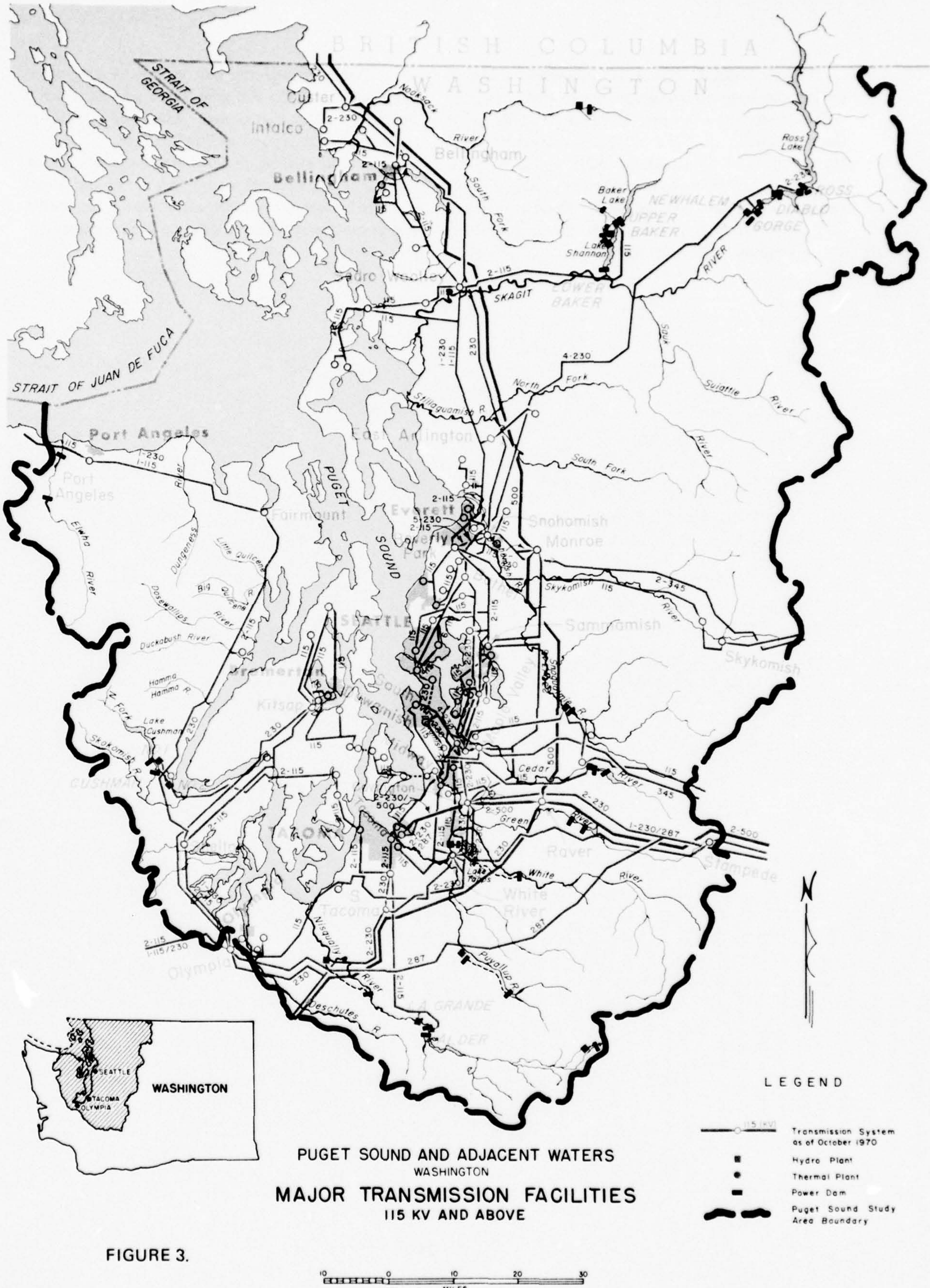
Operating Voltage kv	Circuit Miles	Land Use (acres)
115	745	6,570
230	1,280	16,250
287	90	1,370
345	178	2,650
500	282	5,000
Total	2,575	31,840

POWER DEVELOPMENT IN CONJUNCTION WITH OTHER WATER USES

Construction of a dam and reservoir for power production or any other use has an effect on the stream regimen and thereby, other uses of the stream. Hydroelectric power developments that are properly located, designed and operated can have beneficial effects on water uses such as recreation, fish and wildlife, municipal and industrial water supply, irrigation, navigation and on the control of streamflows for flood control and water quality control through dilution of wastes.

In the early days of hydroelectric power development little consideration was given to its effect on other uses. The increasing population and resultant public demand for all other water based functions and recreational areas has resulted in consideration of other uses in the more recently constructed power developments.

The State of Washington and the Federal Government exercise certain restraints which protect all water users. All non-Federal projects on Federal land, on navigable streams, or that produce power used in interstate commerce are subject to licensing by the Federal Power Commission. All hydroelectric power developers must have a permit, issued by the State through the Department of Water Resources, to appropriate public water. These documents contain conditions of operation to protect the anadromous fishery and other water users on the stream.



PUGET SOUND AND ADJACENT WATERS
WASHINGTON
MAJOR TRANSMISSION FACILITIES
115 KV AND ABOVE

FIGURE 3.

The Federal Power Commission includes general language in licenses to insure that a project will be operated, when practicable, in the interest of flood control, fish and wildlife, navigation, and recreation. The Commission sends copies of the application for license to interested Federal and State agencies for review and comment. These comments may result in FPC hearings and the inclusion of special requirements in the license.

Usable storage capacity at the existing reservoirs is about 2,143,000 acre-feet, a part of which is operated under agreement with the Corps of Engineers in the interest of flood control.

Several existing projects are required to maintain minimum streamflows for fish life by the release of stored water, in addition to providing fish protective or replacement features during construction.

POTENTIAL DEVELOPMENT

HYDROELECTRIC POWER

CONVENTIONAL

This section presents an inventory of the hydroelectric power potential in the Puget Sound Area. One-hundred thirty-seven known power sites were investigated under the following categories.

a. Sites under active consideration.

b. Additions to existing projects.

c. Other sites.

Sites under active consideration and additions to existing projects are discussed, and Tables 7 and 8 list the pertinent information for each.

Potential hydroelectric projects of the Puget Sound Area that are identified as "Other Sites" in the inventory were screened using the guidelines discussed later. Sites with an estimated average power output of less than 10 mw are reported in Table 9. Those with an average output of 10 mw or greater are reported in Table 10. The projects were selected for their potential only, and not because they were considered economically or politically feasible.

An index of economic feasibility was computed for each "other site" with an average power output of 10 mw or more. This index is the benefit-to-cost ratio (B/C) obtained by comparing annual power benefits and annual capital recovery costs of specific power facilities. It provides a measure of the economic feasibility of developing power at multiple-purpose projects which can support much of the cost of dam and reservoir from benefits other than power.

Twelve other sites in Table 10 (average power output of 10 mw or more) with the most favorable B/C ratios were investigated for economic feasibility as single-purpose hydroelectric projects. This analysis, discussed later and reported in Table 11, indicates there are no projects in the Puget Sound Area feasible for development solely as single-purpose power projects at this time.

Nine basin maps, Figures 4 through 12, included with this report show the location of all potential projects reported herein.

The estimated average power output for the sites inventoried in the Puget Sound Area totals almost 1,500 mw. This does not include the 23 sites which are alternatives to sites included in the total.

Sites Under Active Consideration

Sites currently under study or tentatively selected for possible future development have been assigned to this category. They have been somewhat arbitrarily selected and will not necessarily all be constructed. The designation means that some agency has considered them to be worthy of more study. The total installed capacity for projects in this category is 433,000 kw. The projects, with their status and pertinent data, are listed in Table 7.

Additions to Existing Projects

Table 8 lists the additions that are planned or have been suggested for existing plants, which shows a total of 407,520 kw. Possibly other existing hydroelectric plants in the Puget Sound Area could be expanded by raising the dam or increasing generating installation, but economic feasibility of such modification is complex and beyond the scope of this appendix.

Other Sites

a. Guidelines—For the purpose of this appendix the following guidelines were adopted to simplify the computations and to provide a common basis for investigating potential hydroelectric projects.

(1) The inventory includes all known power sites. Political and legislative boundaries (National and State Parks, Wilderness Areas, etc.), existing or planned, were ignored in evaluating the total potential for the Puget Sound Study Area.

(2) The average power output is computed using 100 percent plant efficiency, power discharge of Q50 (the natural flow equaled or exceeded 50 percent of the time), and the maximum static head developed by the project.

(3) Sites with less than 10 mw of average power output are not investigated for economic feasibility.

(4) Installed generating capacity is assumed

to be twice the average power output (50 percent capacity factor).

(5) Annual power benefits are computed using a value of power of $19.81 per kilowatt-year for dependable capacity and 1.30 mills per kilowatt-hour for energy. This is the Federal Power Commission's current value of power, assuming an alternative nuclear plant operating at a 50 percent capacity factor and a composite of private and public non-Federal financing, as explained in more detail in a subsequent section of this appendix titled, "Value of Power."

(6) Specific power costs are estimated for all potential projects 10 mw and over. The annual capital recovery costs are based on 4-5/8 percent interest and 50-year life.

b. Average Power Output and Annual Power Benefits—As stated in the previous paragraph, the average potential power output is based on an overall plant efficiency of 100 percent, maximum static head, and Q50. A power discharge of Q50 may be realistic if some storage regulation is available. Maximum static head and 100 percent efficiency were used for ease of computation. The results show an average power output slightly higher than could actually be realized if a more detailed study were made. A 50 percent capacity factor is used to select an installed capacity that might be operated without downstream reregulation. Dependable capacity is assumed to be equal to the installed capacity. Other sites with an average power output less than 10 mw are listed in Table 9 for a total of 382,900 kw. The average power output and annual power benefits for projects having an average power output of 10 mw or more are shown in Table 10 for a total of 1,028,565 kw.

c. Specific Power Costs—Reconnaissance-type cost estimates of specific power facilities were made for other sites with an average power output of 10 mw or more. Costs for the following specific power facilities are included in this cost estimate: powerhouse and equipment, power intake works, surge tanks, penstocks, operator's colonies, and switchyards. Powerhouse and equipment costs were obtained from estimating curves in a report, "Preliminary Costs and Layouts of Francis Turbine Installation," dated 11 June 1965, prepared by Hydro-Electric Design Branch, North Pacific Division, Corps of Engineers. Costs for the remaining features listed above were obtained from estimating curves prepared by the San Francisco Regional Office, Federal Power Commission, and used by the Corps of Engineers in *preliminary studies for the 1948 Columbia River* Review Report, published as House Document 531, 81st Congress, 2nd Session. The estimated costs have been adjusted to January 1968 price levels by means of the Engineering News Record cost indexes. These estimating curves provide the best means of obtaining costs to use in screening potential hydroelectric projects with the time and funds available.

Annual capital recovery costs of the specific power features are based on 4-5/8 percent interest and a 50-year period. The annual power benefits and annual capital recovery costs of specific power features and benefit-cost ratios are shown in Table 10.

d. The Sites With B/C Ratios Equal to or Greater Than Unity—Table 10 warrants further study as additions to multiple-purpose projects which can support much of the costs of dam and reservoir from benefits other than power.

e. Single-Purpose Hydroelectric Projects—The previous paragraph recommends further study of adding power facilities to projects justified as multiple-purpose projects. In case all of these sites are not considered for development as multiple-purpose projects, it is possible that a site justified for development solely for power might be overlooked. To insure that no power site be overlooked and to establish whether any sites are feasible solely for hydroelectric power development, twelve other sites, most favorable in the specific power cost comparison, were investigated as single-purpose hydroelectric projects.

This was accomplished by comparing annual power benefits and the annual capital recovery costs of developing the total project. Table 11 shows the pertinent information for this analysis. Costs used for this purpose are the construction costs of dam and reservoir added to the costs of specific power features described in paragraph c. Costs of operation, maintenance, and major replacements have not been included.

Because none of the most favorable sites examined appear to be economically feasible for power alone, it appears that there are no projects in the Puget Sound Area feasible for single-purpose power development on the basis of the guidelines used in this report.

TABLE 7. Sites under active consideration

Project	River Mile	Max. Pool Elev. Ft.	Gross Power Head Ft.	Installed Capacity KW	Average Annual Energy KW	Remarks
SNOHOMISH BASIN						
Upper Sultan[1]	16.9	1,450	393[2]	84,000	(	Upper Sultan Dam completed to evaluation 1408, used for water supply storage.
Middle Sultan[1]	13.4	1,060	398[2]	32,000	(41,400	
Lower Sultan[1]	10.3	--	297[3]	24,000	(	Lower Sultan storage in Lake Chaplain. Powerhouse near mile 6.0.
Pilchuck River[4]		--	150	4,000	970	Water supply storage and hydroelectric power.
N.F. Snoqualmie River[6]	11.7	1,572	292	20,000	8,340	
N.F. Snoqualmie River[6]	5.9	1,076[5]	572	30,000	23,300	Storage dam reregulating dam.
SKAGIT-SAMISH BASINS						
Cascade; Cascade River[7]	8	960	628	60,000	26,200	Diversion from Cascade Dam to powerhouse at Copper Creek on Skagit River.
Copper Creek; Skagit River[7]	86	495	163	83,000	43,600	
Thunder Creek[8]	9	2,068	395	--	41,400	Diversion from Thunder Creek to Ross Reservoir. Project would increase output of Ross plant.
Lower Sauk; Sauk River[6]	5	490	210	96,000	55,000	
	Puget Sound Area Total			433,000	240,210	

[1] PUD No. 1 of Snohomish County and city of Everett, application for license, FPC, Project No. 2157, dated June 1, 1961, amended June 7, 1968.

[2] Normal tailwater to maximum operating pool.

[3] *Normal tailwater to normal water surface is forebay.*

[4] City of Snohomish, application for permit, FPC, Project No. 2690, dated September 13, 1968.

[5] Forebay.

[6] Corps of Engineers studies.

7 Seattle City Light Investigations.

[8] Seattle City Light application for permit, FPC Project No. 2657, dated August 14, 1967.

TABLE 8. Additions to existing projects

Project	Basins	River	Installed Capacity KW	Remarks
Gorge	Skagit	Skagit	44,000	Additional Installation, Reported by FPC, 1964 Summary.
Diablo	Skagit	Skagit	120,000	Additional Installation, Reported by FPC, 1964 Summary.
Ross	Skagit	Skagit	40,000	Additional installation based on 125' added head, Q mean of 3710 cfs, with additional total storage capacity of more than 2,000,000 acre-feet.
Snoqualmie No. 1	Snohomish	Snoqualmie	24,000	Additional Installation, Reported by FPC, 1964 Summary.
Tolt (Seattle)	Snohomish	Tolt	5,520	Seattle Water Supply Project. Initial Installation, based on 485' head, Q50 = 134 cfs.
Cedar Falls	Cedar	Cedar	10,000	Additional Installation, Reported by FPC, 1964 Summary.
Eagle Gorge (Hanson)	Green	Green	65,000	U.S.C.E. Flood Control Project. Initial Installation, Reported by FPC, 1964 Summary.
White River (Dieringer)	Puyallup	White	49,000	Additional Installation, Reported by FPC, 1964 Summary.
Mud Mountain	Puyallup	White	50,000	U.S.C.E. Flood Control Project. Initial Installation, Reported by FPC, 1964 Summary.
		Total	407,520	

TABLE 9. Other sites with average power output less than ten megawatts

Project Name	Basin	Stream	Pool Elev. MSL-Ft.	Gross Head Ft.	Flow Q50 CFS	Average Power Output KW	Remarks
Whatcom Cr. No. 1	Nooksack-Sumas	Whatcom Cr.	317	250	90	1,490	Output based on Q mean.
Whatcom Cr. No. 2	Nooksack-Sumas	Whatcom Cr.	67	40	86	290	Output based on Q mean.
				Nooksack-Sumas Basins Total		1,780	
Sloan Cr.	Skagit-Samish	Sloan Cr. & N.F. Sauk	2,350	400	275	9,350	Reservoir on Sloan Cr. Mile 0.7.
Illabot	Skagit-Samish	Illabot Cr.	1,500	1,000	99	8,420	
Buck Cr. 1A	Skagit-Samish	Buck Cr.	2,205	1,200	82	8,360	
				Skagit-Samish Basins Total		26,130	
Silverton	Stillaguamish	Stillaguamish	1,520	120	225	2,300	
				Stillaguamish Basin Total		2,300	
Troublesome No. 1	Snohomish	Troublesome Cr.	4,100	2,300	20	3,810	Blanca Lake storage.
Troublesome No. 2	Snohomish	Troublesome Cr.	1,800	600	63	3,210	
Alturas Lake	Snohomish	E.F. Foss	2,000	505	145	6,220	
Tonga	Snohomish	Foss	1,495	445	255	9,650	
Lake Dorothy	Snohomish	E.F. Miller	3,100	1,000	43	3,660	
East Fork Miller	Snohomish	E.F. Miller	2,100	900	88	6,730	
Miller Forks	Snohomish	Miller	1,165	290	253	6,240	Diversion dams on east & west forks of Miller River.
Beckler	Snohomish	Beckler	1,250	250	408	8,670	
Lake Isabell	Snohomish	May Cr.	2,850	2,210	34	6,410	
Wallace Falls	Snohomish	Wallace	2,080	1,600	66	8,980	
Dry Cr.	Snohomish	N.F. Tolt	1,600	280	145	3,450	
Forks	Snohomish	Tolt	500	140	495	5,890	
Tokul Cr.	Snohomish	Tokul Cr.	--	--	--	1,000	Reported capacity 2,000 kw.
Middle Fork Mile 10.0	Snohomish	N.F. Snoqualmie	890	140	807	5,370	
				Snohomish Basin Total		79,290	

TABLE 9. Other sites with average power output less than ten megawatts (Cont'd)

Project Name	Basin	Stream	Pool Elev. MSL-Ft.	Gross Head Ft.	Flow Q50 CFS	Average Power Output KW	Remarks
Selleck	Cedar-Green	Cedar	930	210	301	5,370	
Sunday Cr.	Cedar-Green	Sunday Cr.	2,000	210	95	1,700	
Weston Site No. 3	Cedar-Green	Green	2,240	340	126	3,640	
Smay Cr.	Cedar-Green	Smay Cr.	1,840	328	88	2,450	
				Cedar-Green Basins Total		13,160	
Echo Lake	Puyallup	Greenwater	3,920	1,000	45	3,820	
Lost Cr.	Puyallup	Greenwater	2,900	500	100	4,250	
Greenwater	Puyallup	Greenwater	2,400	400	70	2,400	
East Fork Rainier	Puyallup	E.F. White	2,575	360	220	6,730	
Huckleberry	Puyallup	White	2,215	195	290	4,810	
West Fork Rainier	Puyallup	W.F. White	2,860	480	70	2,800	
West Fork Mouth	Puyallup	W.F. White	2,400	560	117	5,570	
Mowich No. 1	Puyallup	Mowich	2,475	815	104	7,200	
Mowich No. 1A	Puyallup	N. & S. Fk. Puyallup	2,235	575	138	6,750	
				Puyallup Basin Total		44,330	
12 PM–16	West Sound	Big Quilcene	1,428	384	72	2,350	Alternate Name: Townsend
12 PM–18	West Sound	Big Quilcene	100	100	200	1,700	Alternate Name: Quilcene
12 PM–13	West Sound	Duckabush	1,125	405	219	7,540	
12 PM–14A	West Sound	Duckabush	720	220	252	4,710	
Staircase	West Sound	N.F. Skokomish	960	225	308	5,890	
Steven Streams	West Sound	N.F. Skokomish	1,700	740	74	4,650	
				West Sound Basins Total		26,840	

TABLE 9. Other sites with average power output less than ten megawatts (Cont'd)

Project Name	Basin	Stream	Pool Elev. MSL-Ft.	Gross Head Ft.	Flow Q50 CFS	Average Power Output KW	Remarks
Upper Dungeness	Elwha-Dungeness	Dungeness	2,100	900	74	5,660	
Gold Cr.	Elwha-Dungeness	Dungeness	1,146	358	120	3,600	
Grey Wolf	Elwha-Dungeness	Grey Wolf	1,300	512	110	4,800	
12 PM–23	Elwha-Dungeness	Dungeness	525	365	303	9,400	Alternate Name: Carlsborg
12 PM–24	Elwha-Dungeness	Dungeness	160	160	347	4,720	Alternate Name: Finn Hall
Delabarre Cr.	Elwha-Dungeness	Elwha	2,112	282	72	1,730	
Godkin Cr.	Elwha-Dungeness	Elwha	1,830	120	225	2,300	Diversion below Goodman Creek.
				Elwha-Dungeness Basins Total		32,210	

Total All Basins:

No. of Sites 46

Average Potential Power 226,040 KW

ALTERNATE SITES

Project Name	Basin	Stream	Pool Elev. MSL-Ft.	Gross Head Ft.	Flow Q50 CFS	Average Power Output KW	Remarks
Wells Cr.	Nooksack-Sumas	Wells Cr.	2,130	798	120	8,140	Site inundated if Glacier Site developed (See Table 4).
Trout Cr.	Snohomish	Trout Cr.	1,650	850	81	5,850	Site inundated if Geddings Site developed (See Table 7).
Park Junction 2	Nisqually-Deschutes	Nisqually	1,445	115	535	5,230	Alternate Site for Park Junction (Elbe).
Nisqually	Nisqually-Deschutes	Nisqually	512	87	1,272	9,400	Alternate Site for TR Nisqually.
				Total		28,620	

TABLE 10. Other sites with average power output ten megawatts and over

Project	River	Pool Elev. MSL Ft.	Q50 CFS	Gross Head Ft.	Average Power Output KW	Total Annual Power Benefits $1000	Annual Capital Recovery Power Costs $1000	B/C Ratio	Remarks
NOOKSACK-SUMAS BASINS									
Shuksan	Nooksack	2,130	364	570	17,640	900	1,579	0.6	32,000' diversion
Nooksack Falls	Nooksack	1,780	482	430	17,550	895	756	1.2	6,000' diversion
Warnick	Nooksack	1,025	950	225	18,100	923	400	2.3	28,000' diversion
Maple Falls	Nooksack	590	1,100	270	25,250	1,288	2,210	0.6	24,000' diversion
Deming	Nooksack	315	2,727	130	30,000	1,530	673	2.3	
Wanlick	South Fork Nooksack	1,820	195	1,020	16,910	863	1,814	0.5	
Skookum Creek	South Fork Nooksack	800	544	430	19,900	1,015	398	2.6	
				Total	145,350				
				Total	85,550	Sites with B/C Ratio = 1			
ALTERNATE SITES									
North Fork	Nooksack	2,100	480	322	13,100	668	318	2.1	Alternate to Shuksan
Glacier	Nooksack	1,510	490	315	13,100	668	312	2.1	Alternate to Nooksack Falls
Welcome	Nooksack	385	1,940	120	19,750	1,007	522	1.9	Alternate to Deming
Edfro	South Fork Nooksack	800	530	410	18,500	944	370	2.6	Alternate to Skookum Creek
Whatcom Creek No. 1	Whatcom Creek	300	600	250	12,750	650	Not Estimated	--	Project would divert S.F. Stillaguamish River above Edfro site into Whatcom Lake, thence through powerhouse on Whatcom Creek
				Total	77,200				
SKAGIT-SAMISH BASINS									
Mi. 74-81	Skagit	330	4,300	60	21,930	1,119	2,288	0.5	37,000' diversion
Dalles	Skagit	183	13,500	32	36,720	1,873	2,520	0.7	
Lake Creek	Baker	1,200	500	400	17,000	867	363	2.4	
Hard-Kindy	Cascade	1,400	426	300	10,860	554	289	1.9	
Upper Suiattle	Suiattle	2,400	367	650	20,280	1,034	1,846	0.6	26,000' diversion–Flows include diversion from Canyon Creek
Downey Creek 1	Suiattle	1,770	414	385	13,550	691	1,424	0.5	26,000' diversion
Downey Creek 2 (1A)	Downey Creek	2,500	1,115	191	18,100	923	1,801	0.5	36,000' diversion–Flows include diversion from Sulphide Creek
Buck Creek No. 1	Suiattle	1,385	727	380	23,480	1,198	1,625	0.7	32,000' diversion
Lower Suiattle	Suiattle	1,005	1,000	505	42,800	2,183	3,347	0.6	9 mi. diversion plus 2½ mi. diversion tunnel
Upper Whitechuck	Whitechuck	3,200	150	1,200	15,300	780	1,452	0.5	24,000' diversion
Lower Whitechuck	Whitechuck	1,900	260	800	17,680	902	1,807	0.5	40,000' diversion
North Fork Sauk	North Fork Sauk	1,950	425	845	30,525	1,557	715	2.2	20,000' diversion tunnel
Upper Sauk (Dan Cr.)	Skagit	1,105	1,180	605	60,680	3,095	2,603	1.2	45,000' diversion tunnel
				Total	328,905				
				Total	119,065	Sites with B/C Ratio = 1			

TABLE 10. Other sites with average power output ten megawatts and over (Cont'd)

Project	River	Pool Elev. MSL Ft.	Q50 CFS	Gross Head Ft.	Average Power Output KW	Total Annual Power Benefits $1000	Annual Capital Recovery Power Costs $1000	B/C Ratio	Remarks
ALTERNATE SITES									
Lower Faber	Skagit	288	11,400	120	116,000	5,917	2,008	2.9	Alternate site located between Mi. 74-81 & Dalles
Sulphide Creek	Baker	1,200	485	476	19,620	1,001	1,558	0.6	19,000' diversion—Alternate to Lake Creek
Upper Sauk Alternate	Skagit	1,105	1,180	195	19,500	995	422	2.4	Alternate development of Upper Sauk (Dam Creek). Powerhouse at dam
				Total	155,120				
STILLAGUAMISH BASIN									
Tyree	South Fork Stillaguamish	1,400	620	390	20,550	1,048	438	2.4	
Robe	South Fork Stillaguamish	1,010	905	540	41,500	2,117	1,440	1.5	6,000' diversion—Flows include diversion from Canyon Creek
Granite Falls	South Fork Stillaguamish	470	970	255	21,000	1,071	833	1.3	5,000' diversion
Jordan	South Fork Stillaguamish	215	1,190	117	11,850	604	380	1.6	
Frailey Mountain	Deer Creek Lk. Cavanaugh	1,020	350	820	24,400	1,245	872	1.4	Deer Creek diversion with storage in Lake Cavanaugh, 3,500' tunnel diversion to powerhouse
Oso	North Fork Stillaguamish	194	1,400	136	16,200	826	450	1.8	
				Total	135,500				
				Total	135,500 Sites with B/C Ratio = 1				
ALTERNATE SITE									
Robe Alternate	South Fork Stillaguamish	1,010	905	370	28,400	1,449	487	3.0	Alternate development of Robe site powerhouse at dam
SNOHOMISH BASIN									
Upper South Fork	South Fork Skykomish	1,010	1,080	120	11,000	561	952	0.6	14,000' diversion
Sunset Falls	South Fork Skykomish	640	1,706	160	23,200	1,183	639	1.9	1,500' diversion
Giddings Creek	North Fork Skykomish	1,100	812	330	22,700	1,158	425	2.7	Alternate name: North Fork
Winters	Sultan	295	710	185	11,200	571	1,060	0.5	2,000' diversion
Twin Falls	South Fork Snoqualmie	1,000	310	500	13,200	673	460	1.5	3,000' diversion
				Total	81,300				
				Total	59,100 Sites with B/C Ratio = 1				
ALTERNATE SITE									
Silver Creek	North Fork Skykomish	1,100	525	300	13,400	684	921	0.7	1,800' diversion—Project would overlap Giddings Creek project

TABLE 10. Other sites with average power output ten megawatts and over (Cont'd)

Project	River	Pool Elev MSL Ft.	Q50 CFS	Gross Head Ft.	Average Power Output KW	Total Annual Power Benefits $1000	Annual Capital Recovery Power Costs $1000	B/C Ratio	Remarks
PUYALLUP BASIN									
Twin Creek	White	1,850	800	530	36,000	1,836	623	2.9	
Fairfax	Carbon	1,460	345	830	24,300	1,240	1,490	0.8	17,000' diversion
Mile 9.2	Carbon	630	371	380	12,000	612	1,045	0.6	17,500' diversion
Orting	Puyallup	630	590	270	13,500	689	1,070	0.6	16,500' diversion
				Total	85,800				
				Total	36,000	Sites with B/C Ratio 1			
ALTERNATE SITES									
Deadman Flat	White	1,685	754	385	24,700	1,260	1,280	0.98	10,500' diversion–Alternate to Twin Creek
Carbon No. 1	Carbon	2,015	224	705	13,400	684	1,637	0.4	44,000' diversion) Three sites) are alternate
Carbon No. 2	Carbon	1,290	330	470	13,200	673	1,314	0.5	24,000' diversion) to Fairfax) and Mile 9.2
Carbon No. 3	Carbon	820	330	480	13,500	689	1,368	0.5	26,000' diversion) sites
				Total	64,800				
NISQUALLY DESCHUTES BASINS									
Park Junction (Elbe)	Nisqually	1,995	317	798	21,500	1,097	2,874	0.4	68,000' diversion
TR Nisqually	Nisqually	515	1,272	140	15,140	772	1,890	0.4	32,000' diversion
				Total	36,640				
				Total	None	Sites with B/C Ratio 1			
ALTERNATE SITE									
Park Junction 1	Nisqually	1,995	317	550	14,800	755	2,168	0.3	42,000' diversion–Alternate to Park Junction (Elbe)
WEST SOUND BASINS									
Tunnel Creek	Big Quilcene	1,044	146	944	11,700	597	1,163	0.5	25,000' diversion
12 PM-10	Dosewallips	1,520	280	740	17,600	898	992	0.9	11,000' diversion
12 PM-11	Dosewallips	780	310	380	10,000	510	882	0.6	17,000' diversion
Rocky Brook	Dosewallips	400	438	400	14,900	760	1,188	0.6	17,500' diversion–Alternate name 12 PM-12
Duckabush	Duckabush	500	310	440	11,600	592	922	0.6	15,000' diversion
Hamma Hamma	Hamma Hamma	540	442	535	20,100	1,025	736	1.4	4,500' diversion
Brown Creek	South Fork Skykomish	735	307	625	16,300	831	2,332	0.4	36,000' diversion
				Total	102,200				
				Total	20,100	Sites with B/C Ratio 1			

TABLE 10. Other sites with average power output ten megawatts and over (Cont'd)

Project	River	Pool Elev. MSL Ft.	Q50 CFS	Gross Head Ft.	Average Power Output KW	Total Annual Power Benefits $1000	Annual Capital Recovery Power Costs $1000	B/C Ratio	Remarks
ELWHA-DUNGENESS BASINS									
Press Valley	Elwha	1,710	477	310	12,570	641	694	0.9	
Grand Canyon	Elwha	1,400	734	430	26,800	1,367	463	3.0	
Geyser Basin	Elwha	970	873	362	27,000	1,377	485	2.8	
McDonald	Elwha	412	1,102	212	19,900	1,015	1,486	0.7	17,000' diversion
Tailwater	Elwha	84	1,418	84	10,100	515	727	0.7	7,500' diversion
Forks	Dungeness	1,200	287	675	16,500	842	1,301	0.6	21,000' diversion
				Total	112,870				
				Total	53,800	Sites with B/C Ratio 1			
ALTERNATE SITES									
Little Lost	Elwha	1,380	575	290	14,170	723	1,095	0.7	Little Lost and Windfall Creeks are alternate to Grand Canyon
Windfall Creek	Elwha	1,090	612	290	15,100	770	1,156	0.7	
				Total	29,270				

TABLE 11. Analysis of potential single-purpose hydroelectric projects

Project	River Basin	Average Power Output KW	Total Annual Power Benefits $1000	Project Costs Total $1000	Project Costs Annual $1000	B/C Ratio
North Fork	Nooksack-Sumas	13,100	668	55,254	2,698	0.25
Welcome	Nooksack-Sumas	19,750	1,007	113,437	5,857	0.17
Deming	Nooksack-Sumas	30,000	1,530	85,271	4,403	0.35
Nooksack Falls	Nooksack-Sumas	17,550	895	22,598	1,167	0.77
Lower Faber	Skagit-Samish	116,000	5,917	235,804	12,175	0.49
Upper Sauk (Alt)	Skagit-Samish	26,000	1,326	91,886	4,744	0.28
Robe	Stillaguamish	41,500	2,117	70,959	3,664	0.58
Robe (Alt)	Stillaguamish	28,400	1,449	54,410	2,809	0.52
Tyree	Stillaguamish	20,550	1,048	82,287	4,248	0.25
Jordan	Stillaguamish	11,850	604	25,445	1,314	0.46
Oso	Stillaguamish	16,200	826	42,448	2,192	0.38
Frailey Mountain	Stillaguamish	24,400	1,245	48,370	2,497	0.50

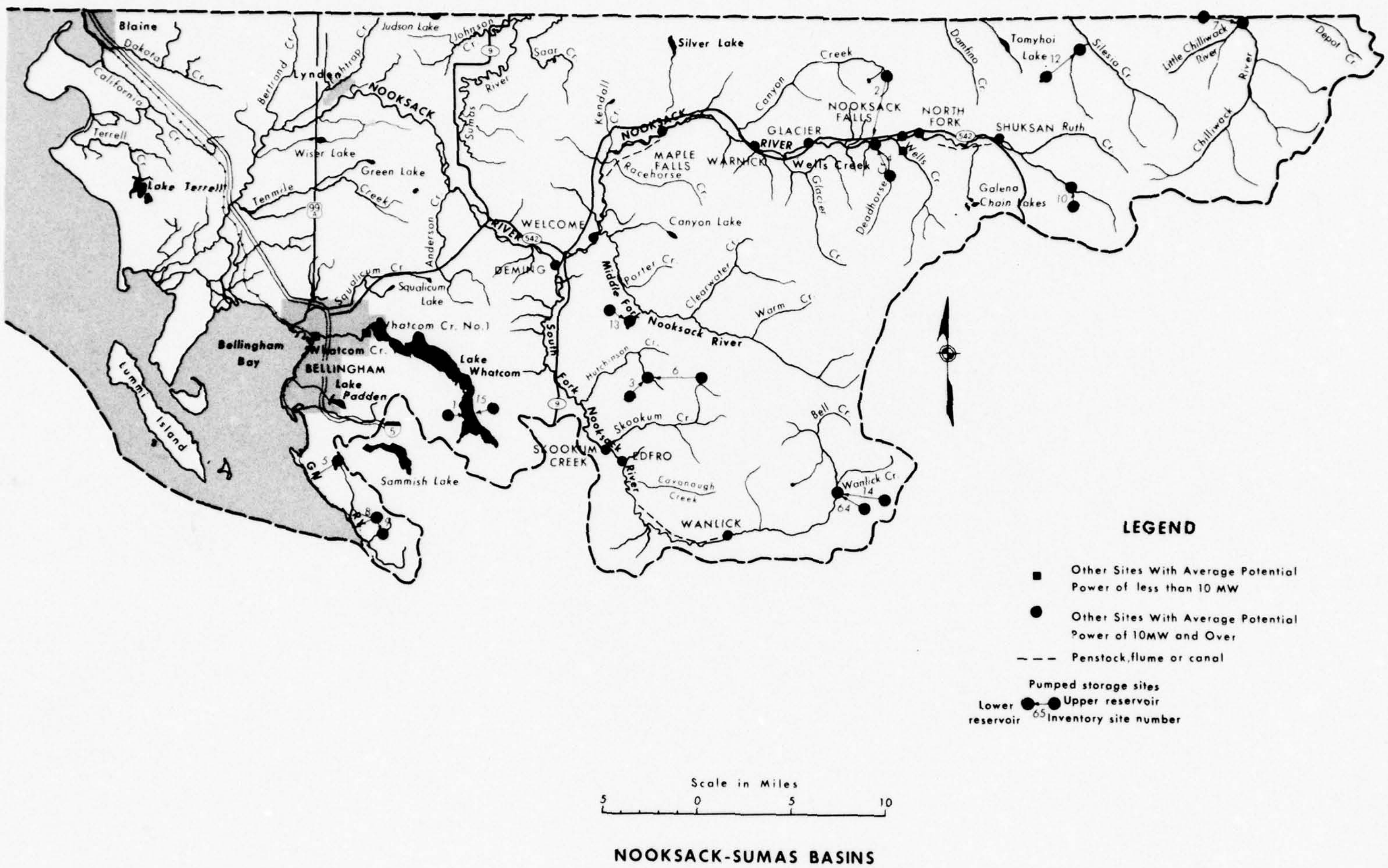


FIGURE 4. Potential hydroelectric power sites, Nooksack-Sumas Basins.

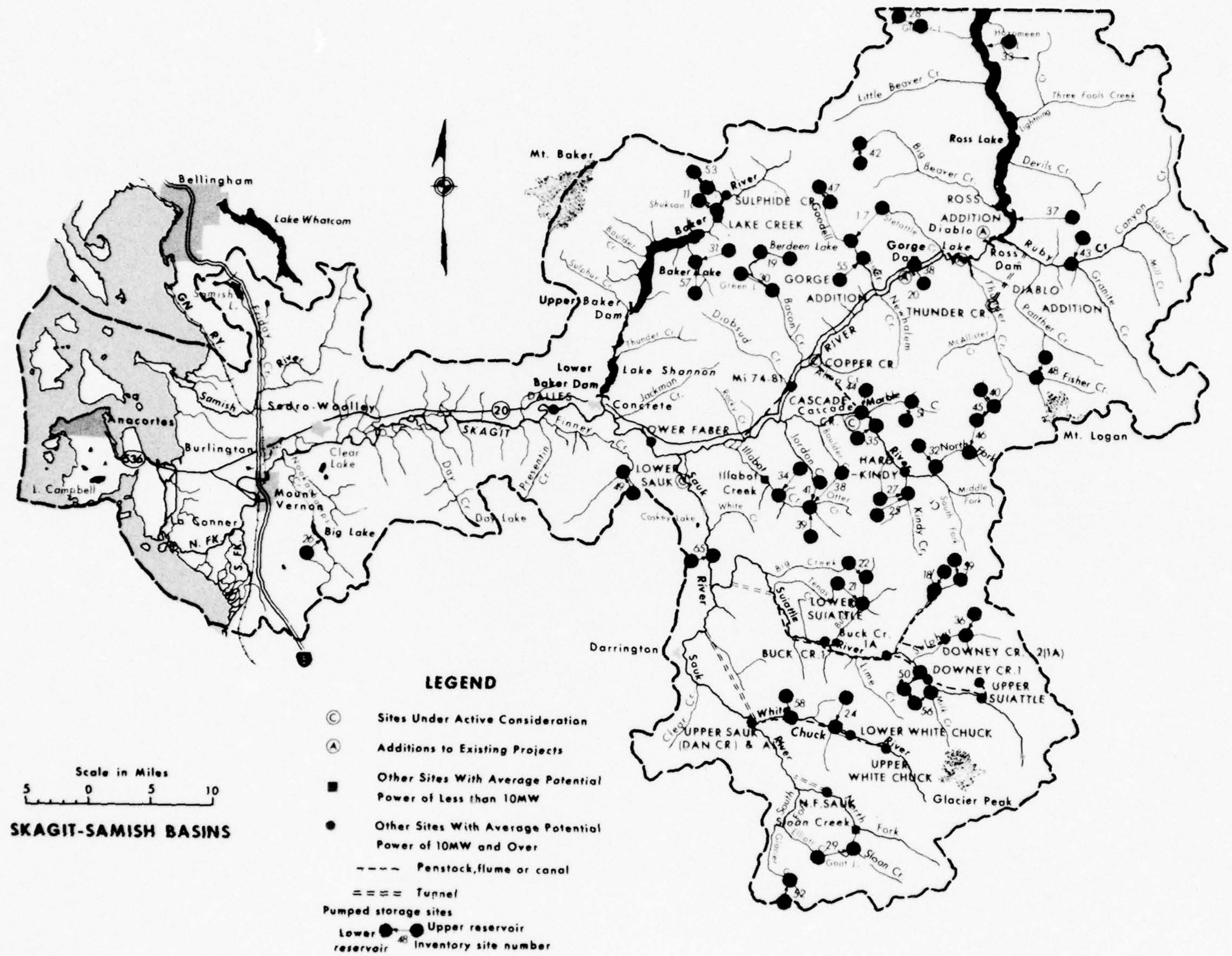


FIGURE 5. Potential hydroelectric power sites, Skagit-Samish Basins.

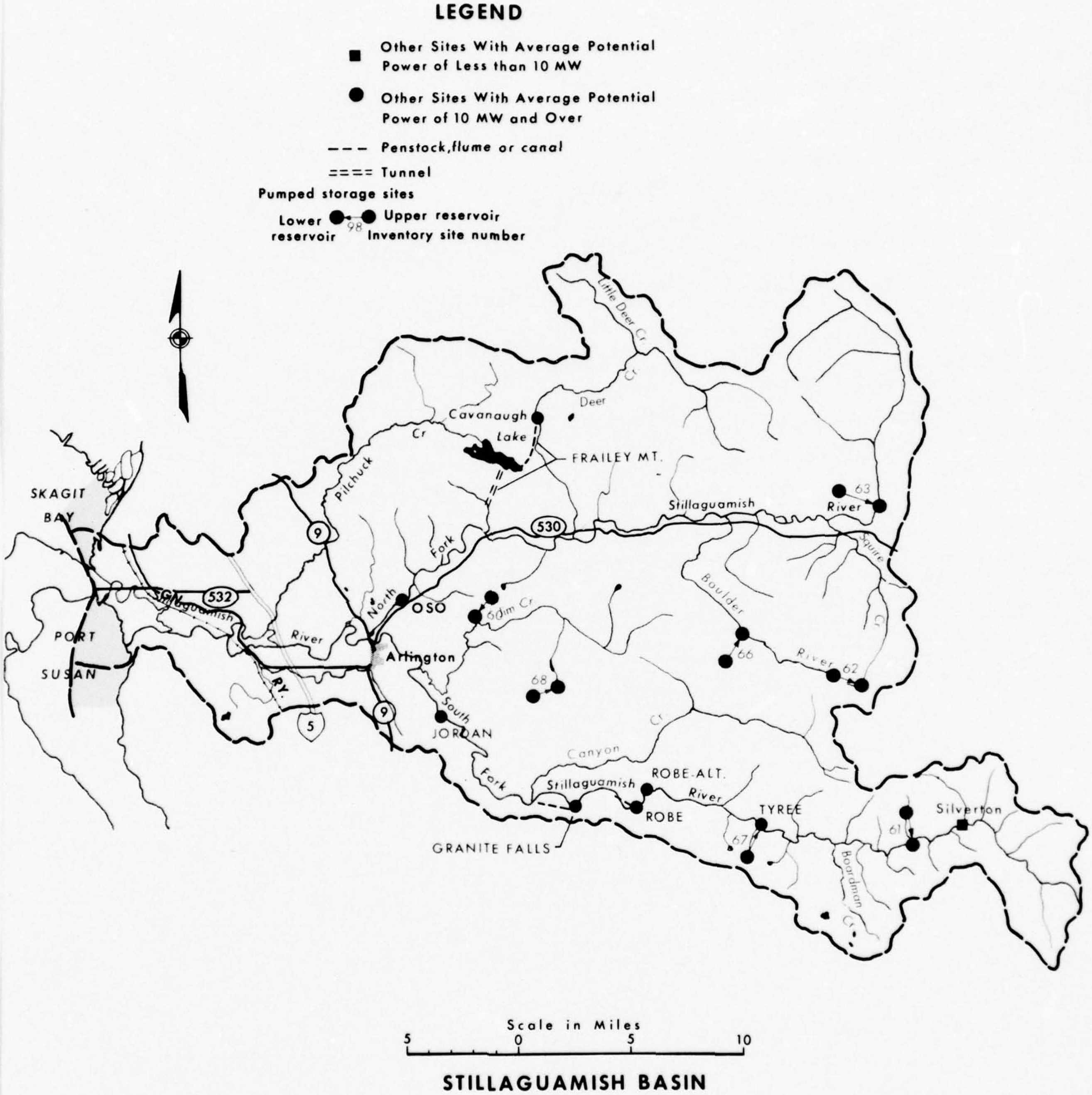
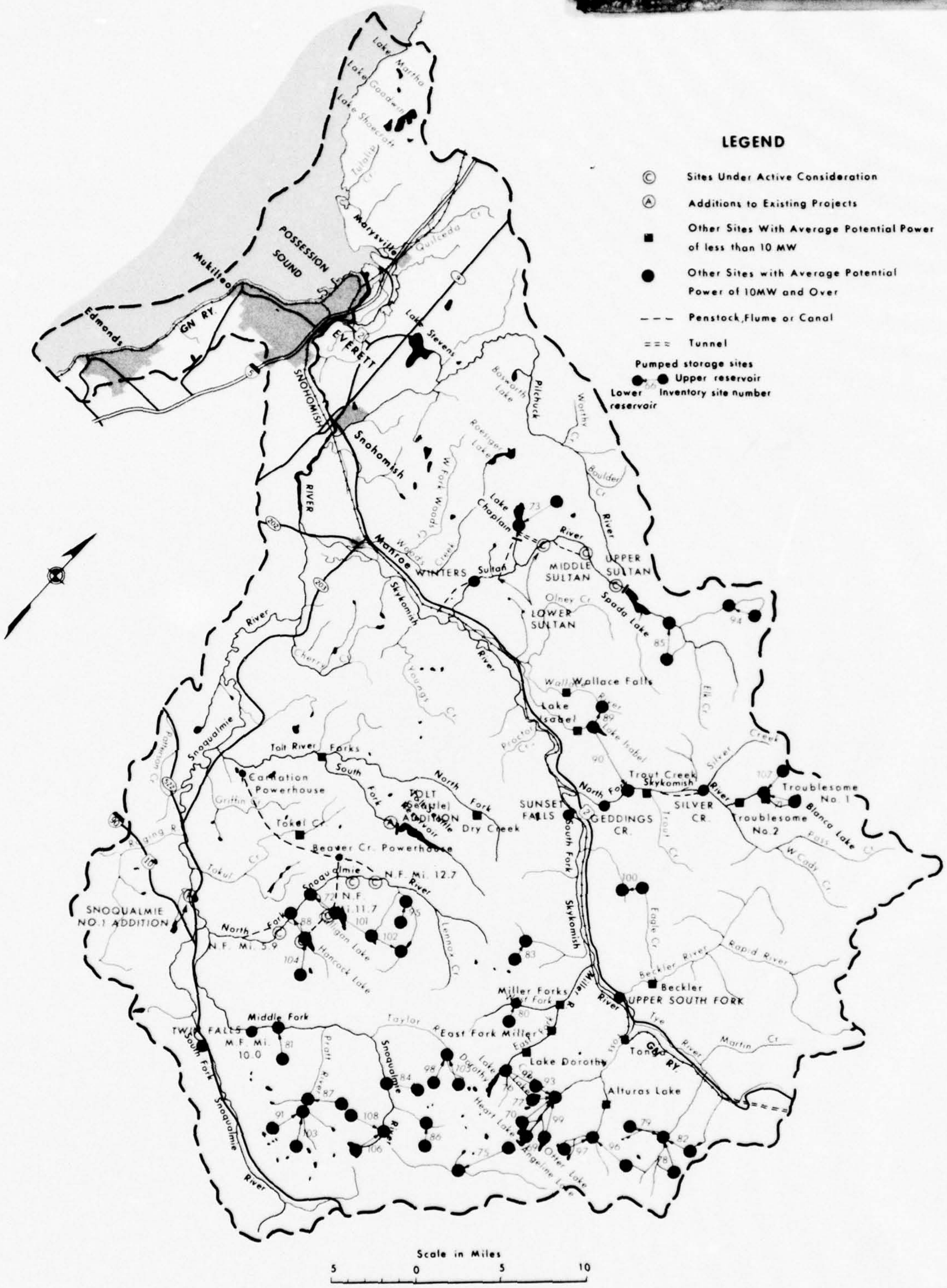


FIGURE 6. Potential hydroelectric power sites, Stillaguamish Basin.



SNOHOMISH BASIN

FIGURE 7. Potential hydroelectric power sites, Snohomish Basin.

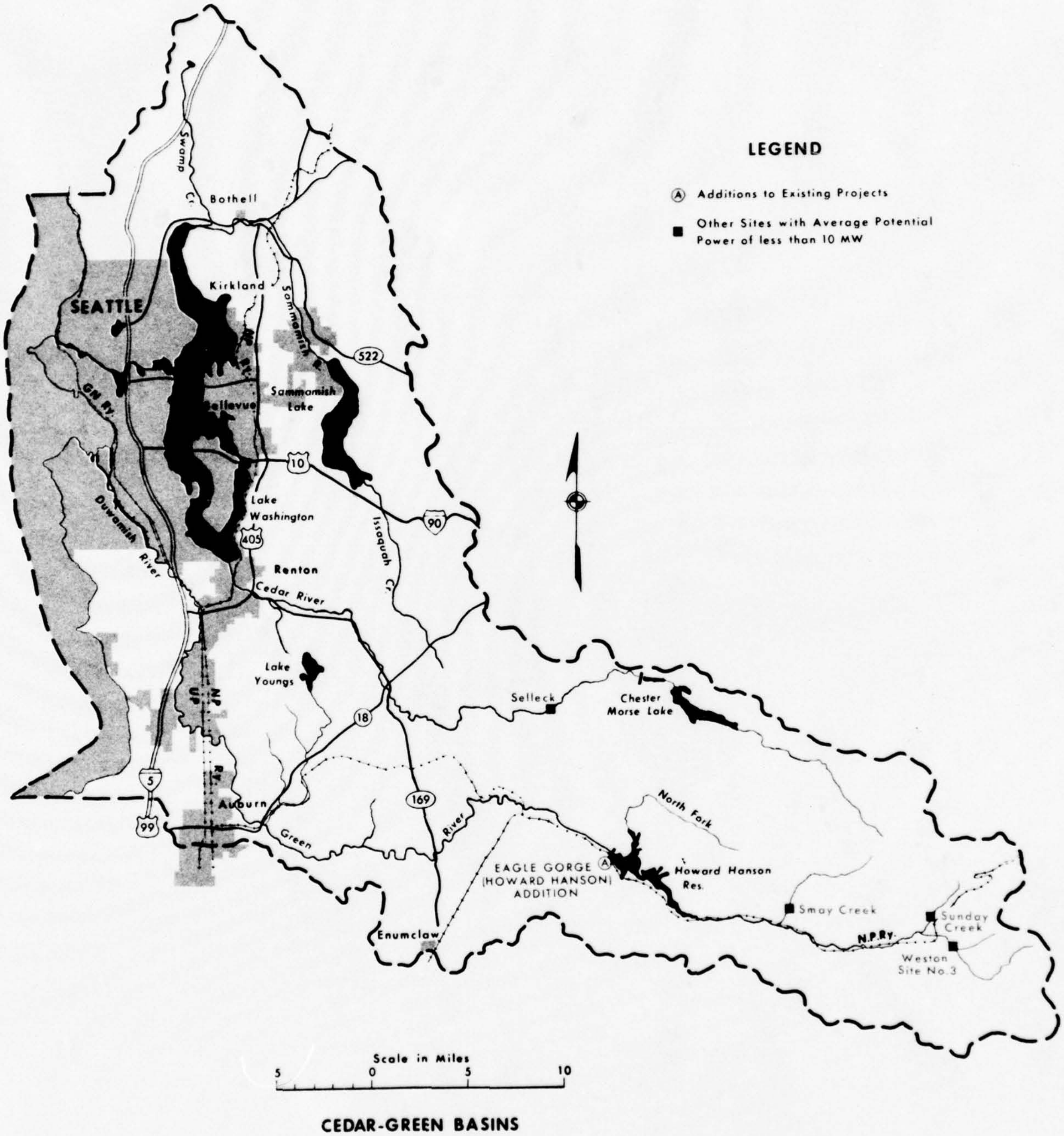


FIGURE 8. Potential hydroelectric power sites, Cedar-Green Basins.

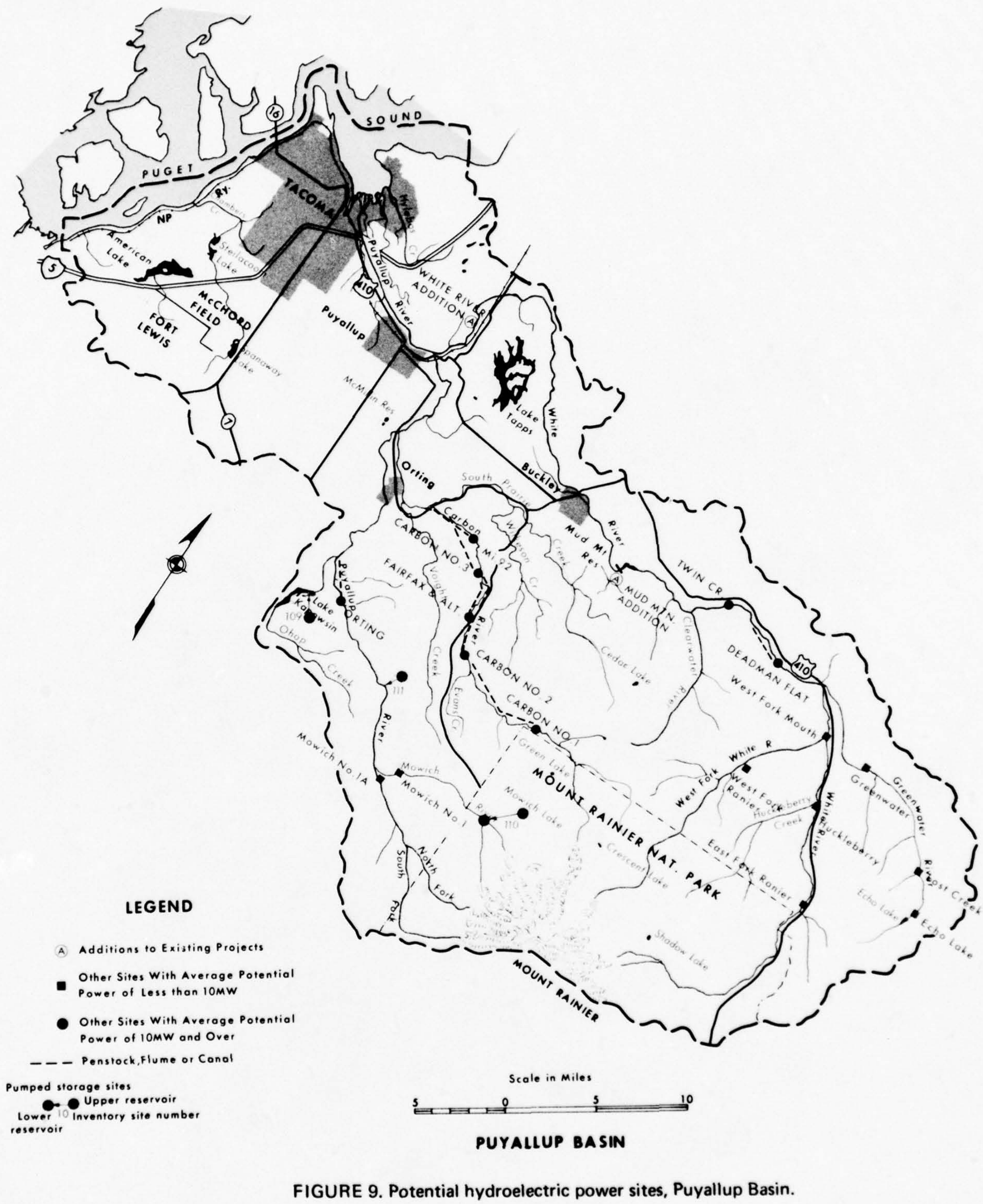


FIGURE 9. Potential hydroelectric power sites, Puyallup Basin.

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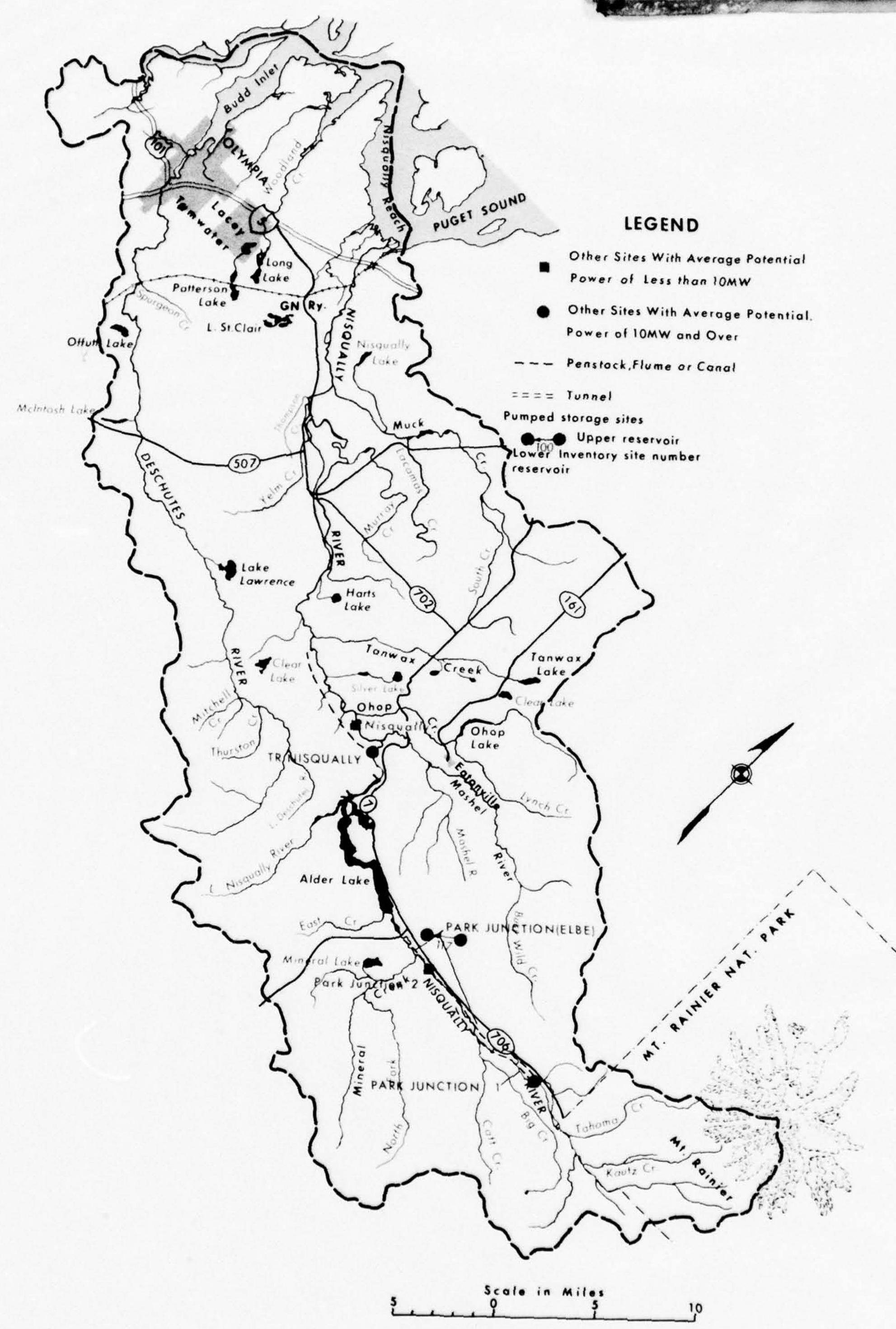


FIGURE 10. Potential hydroelectric power sites, Nisqually-Deschutes Basins.

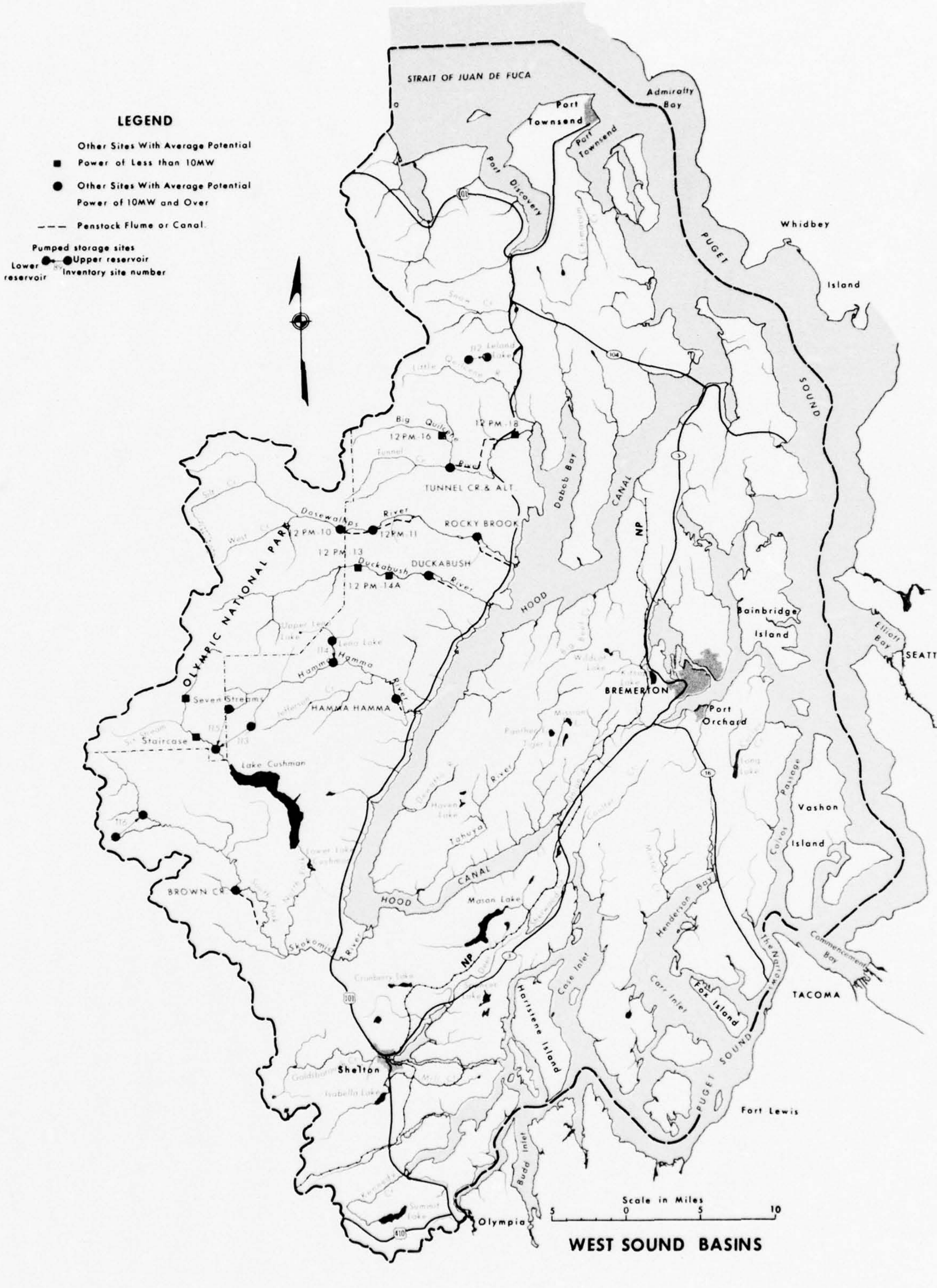


FIGURE 11. Potential hydroelectric power sites, West Sound Basins.

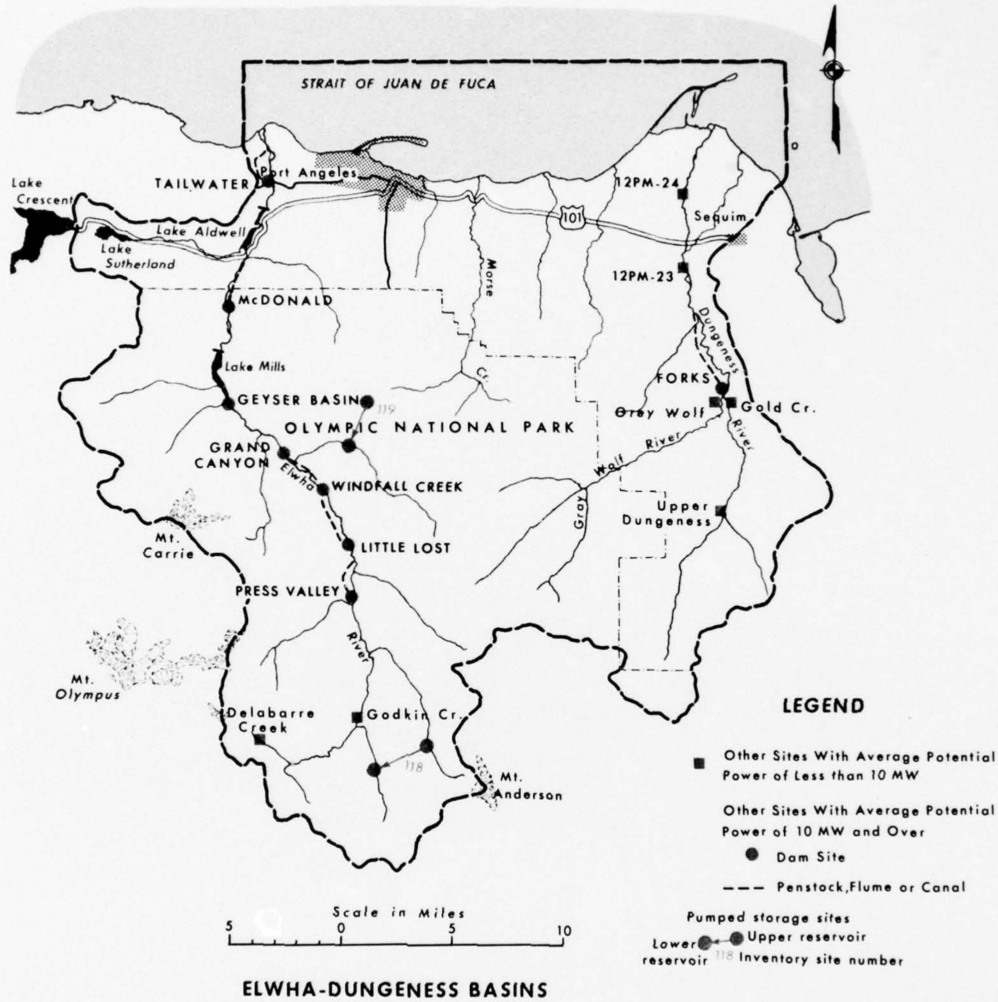


FIGURE 12. Potential hydroelectric power sites, Elwha-Dungeness Basins.

PUMPED-STORAGE

Electrical resource studies indicate that in the future the major part of the Pacific Northwest's base load will be met by nuclear power plants. Nuclear plants, although supplying relatively low cost base load energy, are an expensive source of peaking power. Therefore, more economical means for providing peaking power must be sought. Studies indicate that the peaking requirements of the Area will be met until about 1990 by adding units at existing conventional hydroelectric projects. When the addition of those units is completed, other sources of peaking power must be developed. Of the several alternatives available, one of the most promising is pumped-storage.

The topography of much of the Puget Sound Study Area is unusually favorable for the development of pumped-storage. A site survey has been conducted, and it has been found that there are well over one-hundred sites available in the Study Area which are potentially suitable for the development of large daily/weekly cycle pumped-storage plants.

Operation

Pumped-storage is unique among methods of power generation as it is dependent on other electrical power sources for its energy supply. It functions as an energy accumulator in that low-valued off-peak energy (generated at thermal electric or other conventional power plants) is stored by pumping water from a lower to a higher reservoir (see Figure 13). The stored water can then be returned through the turbines to generate power during peak-load periods, when it is most needed and has its greatest value. Pumped-storage installations offer many of the advantages of conventional hydroelectric plants including rapid start-up, long life, dependability, low operating and maintenance costs, and adaptability as low cost spinning reserve. With respect to the adaptability as low cost spinning reserve, the reversible pump-turbines of pumped-storage installations offer a double reserve capability. First, their own generating capacity is available to meet peak loads. Second, during the pumping portion of the operating cycle, the power used for pumping can be quickly interrupted if the system load suddenly increases, minimizing the possibility of overloading the system's transmission facilities.

Pumped-storage may be designed to operate on a seasonal, weekly, or a daily cycle. Seasonal pumped-storage would be economical in a system where there is a period in the year in which there is both surplus water and surplus energy. The surplus energy would be used to pump the surplus water into a holding reservoir to be used for generation during periods of greatest power demand. In the Puget Sound Study Area, however, the streamflow and power demand patterns do not appear to be favorable for seasonal pumped-storage operation. Daily and weekly pumped-storage hold considerable promise, especially in light of the fact that in the near future thermal plants will begin assuming an increasing share of the Area's base load. As more thermal plants are put into operation, more off-peak energy will become available for potential use by pumped-storage plants. Water can be pumped at night (and on week-ends) and released during the day to generate energy for meeting the system's peak loads (see Figure 14). Due to transmission losses and inefficiencies in the operation of the pump-turbines, approximately one and one-half times as much energy is required for pumping as is obtained in the generating phase. However, this increased energy use is justified by the high value of the peak generation.

Site Inventory

In developing the pumped-storage site inventory, most of the effort was placed in locating sites suitable for large peaking plants capable of operating on a daily or weekly cycle using off-peak thermal energy. In selecting the sites, a number of factors were taken into consideration including topography, plant operating pattern, plant size, machinery characteristics, reservoir size and characteristics, penstock size and length, and source of energy. These factors are discussed in detail under Site Selection Criteria and Procedures, which follows Table 13.

The 115 potential sites having an investment cost of less than $150 per kilowatt are listed in Table 12. The locations of these sites are shown on the basin maps, Figures 4 through 12. It should be noted that several of the sites are mutually exclusive alternatives. Maximum capability and detailed cost studies were made on twelve typical sites and the resulting costs and characteristics are summarized in Table 13.

Costs

On the basis of the cost data shown in Table 13, it appears that it will be possible to construct pumped-storage having an annual cost of about $6.50

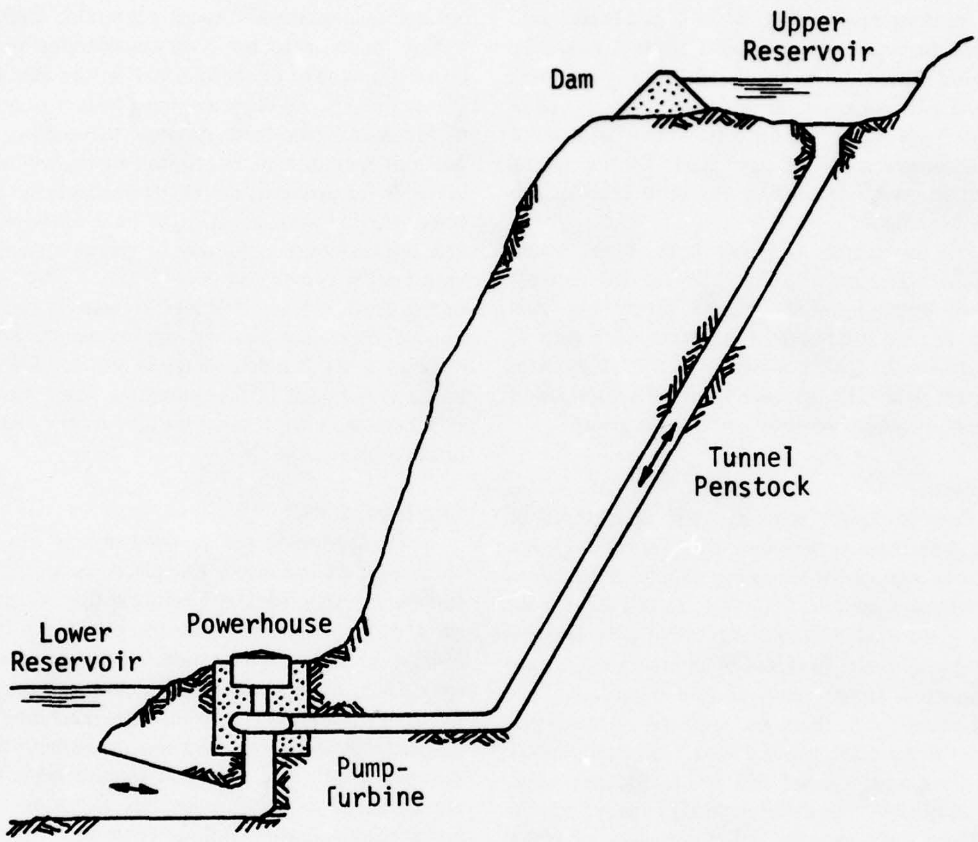


FIGURE 13. Typical pumped-storage project.

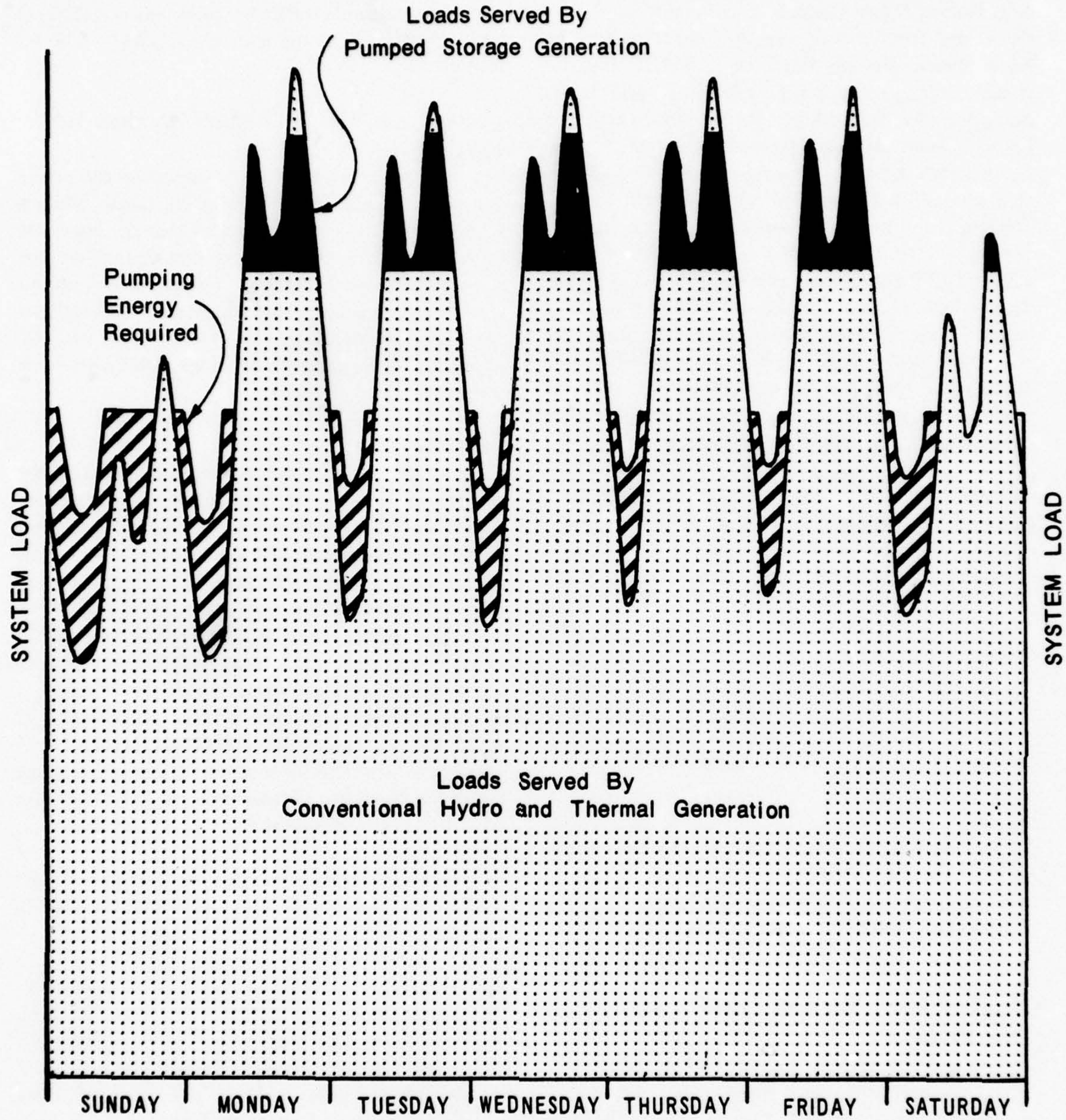


FIGURE 14. Typical weekly system load curve.

per kilowatt based on 4-5/8 percent Federal financing. Federal Power Commission studies indicate that the annual fixed cost of nuclear thermal capacity at 4-5/8 percent Federal financing is $14.26 and the variable (energy) cost is 1.27 mills per kilowatt-hour. Assuming that the peaking capacity will be required for 876 hours per year (10 percent annual capacity factor), that off-peak pumping energy will be available at 1.27 mills per kwh, and that 1½ kwh of pumping energy will be required for each kwh of peaking energy, the cost of pumped-storage capacity will be $8.17 per kw-year as compared to $15.37 per kw-year for nuclear thermal capacity. Again using current Federal Power Commission cost data, the tabulation below indicates that pumped-storage at $6.50 per kw-year is more economical than both gas turbine and steam-electric peaking plants down to annual capacity factors of about 2 percent.

Annual Capacity Factor Percent	Pumped-Storage $/KW-Year[1]	Gas Turbines $/KW-Year[2]	Steam-Electric Peaking $/KW-Year[2]
25	10.67	--	17.14
20	9.84	--	15.20
15	9.00	--	13.21
10	8.17	17.73	11.06
5	7.34	11.24	8.75
2½	6.92	7.99	7.45
1	6.67	5.96	--

[1] Based upon capacity cost of $6.50 per kw-year and energy costs of 1.5 x 1.27 mills/kwh.

[2] Based on financing comparable to that used in computing pumped-storage costs (4-5/8% over 50 years).

Effect of Pumped-Storage Plant Operation on Streamflow

Nearly all of the sites located in this survey would be developed as hydraulically independent projects; the reservoirs would be comparatively small and would be used exclusively for pumped-storage operations. The large, irregular flows associated with peaking operations would occur only between the upper and lower reservoirs. Once filled, only a comparatively small amount of inflow would be required to make up leakage and evaporation losses. For the most part inflows would be passed, and the operation of the project would have very little effect on the flows downstream. In some cases, however, a reservoir drawdown would be quite severe and therefore public access to the reservoirs would have to be restricted.

Recreational Use of Pumped-Storage Reservoirs

Almost every reservoir is viewed by the public as a potential site for water-based recreation. While it is probable that some pumped-storage reservoirs could be used for recreation, at least during that part of the year when the peaking demand is low, not all would be amenable to the structural or operational modifications necessary for recreational use. Of necessity, public access to the latter would have to be restricted.

Best Sites

All of the 115 sites surveyed (Table 12), are capable of a 1000 mw installation, and some are capable of 5,000 mw or more. Although these sites all show favorable investment costs, other factors will render some of them infeasible. Some are located in National Parks, Wilderness Areas, or other prime recreation areas; some would conflict with other existing land and water uses; and others might be impractical from a geological standpoint. While it is not appropriate at this time to make a final judgment as to the desirability of individual projects, it is possible to point out some of the factors which might affect the feasibility of these projects, and to indicate which of these sites appear to be most favorable.

The following table lists the number of sites which fall into special land and water use classifications:

National Parks	24 sites
Wilderness Areas	12 sites
Proposed Wilderness Areas	13 sites
Other USFS Special Designated Areas	2 sites
Proposed Wild Rivers	2 sites
Ross Lake National Recreation Area	2 sites
Municipal Water Supply Reservoirs	3 sites
Total	58 sites

In addition, nine sites are located in other heavily used recreation areas within the National Forest System and two sites have heavily developed lower reservoirs.

This leaves 46 sites having no apparent major conflicts. Of the 115 sites surveyed, these appear to be the most favorable and should be given prior consideration for more detailed investigation. It should be emphasized that these sites are considered to be the most promising of the sites reviewed; however, this should not preclude the other sites from consideration in further studies.

Summary

It appears from this survey that there is considerable pumped-storage potential in the Puget Sound Study Area; potential that could be developed in conjunction with thermal base load plants. Considering only the minimum installation at the 46 most favorable sites, there is a potential of 46,000 mw. On the basis of the costs obtained for sites studied thus far, it is estimated that a substantial amount of pumped-storage peaking capacity could be installed at $90 to $130 per kilowatt. More study will be required to see how pumped storage could best fit into the Area's future load pattern, but it is evident that pumped-storage offers considerable promise as a source of future peaking capacity.

TABLE 12. Potential pumped-storage sites in the Puget Sound Study Area, minimum site capacity 1000 MW

No.	Site	Approximate Head, Feet	Maximum Plant Capacity, MW[2]	Special Land Designation[1]
		NOOKSACK-SUMAS BASINS		
1	Austin	1,180	2,000	MWS
2	Bearpaw Mountain	2,100	3,000	
3	Blue Mountain	1,260	3,000	
4	Bridge Camp	2,320	5,000	
5	Chuckanut Mountain	1,080	6,000	
6	Dailey Prairie	2,120	3,000	
7	Hanging Lake	2,420	5,000	NP
8	Lilly Lake No. 1	2,090	2,000	
9	Lilly Lake No. 2	1,520	1,000	
10	Price Lake	1,280	1,000	SDA
12	Skagway Pass	2,520	3,000	
13	Van Zandt	1,450	1,000	
14	Washington Monument	1,570	4,000	
15	Wickersham Trail	2,240	2,000	MWS
64	Springsteen Lake	1,880	1,000	
		SAN JUAN ISLANDS		
16	(deleted)[2]			
		SKAGIT-SAMISH BASINS		
11	Shuksan Lake	2,850	4,000	NP
17	Azure Lake	2,800	5,000	NP
18	Bench Lake	2,800	2,000	WA
19	Berdeen Lake	3,300	6,000	NP
20	(deleted)[2]			

[1] NP National Park
WA Wilderness Area
PWA Proposed Wilderness Area
SP State Park
SDA USFS Special Designated Area other than Wilderness Area
NRA National Recreation Area (Ross Lake)
PWR Proposed Wild River
MWS Municipal Water Supply

[2] Insufficient reservoir capacity for developing 1000 mw.

TABLE 12. Potential pumped-storage sites in the Puget Sound Study Area, minimum site capacity 1000 MW (Cont'd)

No.	Site	Approximate Head, Feet	Maximum Plant Capacity, MW[2]	Special Land Designation[1]
	SKAGIT-SAMISH BASINS (Cont'd)			
21	Boulder Lake	3,000	4,000	WA
22	Crater Lake	2,200	3,000	WA
23	(deleted)[2]			
24	Crystal Lake	2,680	3,000	
25	Cyclone Lake	3,880	6,000	WA
26	Devils Lake	840	1,000	
27	Found Lake	2,520	8,000	WA
28	Glacier Lake	3,400	7,000	NP
29	Goat Lake	920	1,000	
30	Green Lake	3,380	10,000	NP
31	Hidden Creek	1,900	3,000	NP
32	Hidden Lake	3,800	4,000	NP
33	Hozomeen Lake	1,200	5,000	NRA
34	Illabot	2,420	3,000	
35	Irene Creek	2,100	2,000	PWR
36	Itswoot Lake	2,500	1,000	WA
37	Jerry Lakes	4,600	10,000	WA
38	Jordan-Granite Lake	2,200	6,000	WA
39	Jug Lake	1,590	1,000	
40	Klawatti	2,000	1,000	NP
41	Lower Jordan	1,750	2,000	
42	Lung Lake	1,840	1,000	NP
43	McMillan Park	3,360	1,000	WA
44	Monogram Lake	4,000	2,000	NP
45	Moraine Lake No. 1	1,200	1,000	NP
46	Moraine Lake No. 2	1,880	1,000	NP
47	Pioneer Ridge	2,400	1,000	NP
48	Ragged Ridge	1,400	1,000	NP
49	Rinker Ridge	1,640	1,000	
50	Rivord Lake	3,700	3,000	WA
51	Sibley Creek	1,800	1,000	NP
52	Silver Lake	1,710	1,000	
53	Sulphide	2,600	1,000	NP
54	(deleted)[2]			
55	Trappers Peak	3,550	2,000	NP
56	Unnamed Lake	3,000	1,000	WA
57	Watson Lakes	2,670	6,000	
58	White Chuck	3,180	1,000	
59	Woods Lake	2,200	1,000	WA
65	Texas Pond	1,200	1,000	PWR

[1] NP National Park
WA Wilderness Area
PWA Proposed Wilderness Area
SP State Park
SDA USFS Special Designated Area other than Wilderness Area
NRA National Recreation Area (Ross Lake)
PWR Proposed Wild River
MWS Municipal Water Supply

[2] *Insufficient reservoir capacity for developing 1000 mw.*

TABLE 12. Potential pumped-storage sites in the Puget Sound Study Area, minimum site capacity 1000 MW (Cont'd)

No.	Site	Approximate Head, Feet	Maximum Plant Capacity, MW[2]	Special Land Designation[1]
	STILLAGUAMISH BASIN			
60	Ebey Hill	1,300	1,000	
61	Marten Creek	1,310	3,000	
62	Mt. Bullon	2,160	2,000	
63	Segelsen Ridge	1,410	1,000	
66	Tupso Pass	1,200	1,000	
67	Twenty-Two	1,520	2,000	SDA
68	(deleted)[2]			
	SNOHOMISH BASIN			
69	Angeline Lake	2,460	5,000	PWA
70	Big Heart Lake	2,360	4,000	PWA
71	Blanco Lake	1,980	3,000	
72	Calligan Lake	1,100	10,000	
73	(deleted)[2]			
74	Chaplain No. 2	880	1,000	MWS
75	Chetwoot Lake	1,670	3,000	PWA
76	Copper Lake No. 1	1,240	1,000	PWA
77	Copper Lake No. 2	1,760	3,000	PWA
78	Deception Lakes	1,960	3,000	PWA
79	Fisher Lake	1,620	1,000	PWA
80	Francis Lake	2,240	2,000	
81	Gifford Lakes	2,310	6,000	
82	Glacier Lakes	1,780	2,000	PWA
83	(deleted)[2]			
84	Green Ridge Lake	2,820	2,000	
85	Greider Lake	1,760	3,000	MWS
86	Hester Lake	1,370	2,000	
87	Lake Caroline	2,800	3,000	
88	Lake Hancock	1,050	10,000	
89	Lake Isabel No. 1	860	4,000	
90	Lake Isabel No. 2	2,120	10,000	
91	Lake Kulla	1,740	2,000	
92	Lake Malachite No. 1	1,400	1,000	PWA
93	Lake Malachite No. 2	1,920	2,000	PWA
94	Little Chief Peak	1,310	3,000	
95	Loch Katrine	1,440	2,000	
96	Marmot Lake	2,640	4,000	PWA
97	Necklace Valley	2,480	4,000	PWA
98	Nordrum Lake	1,940	3,000	
99	Otter Lake	1,760	3,000	PWA
100	Paradise Meadow	1,630	3,000	

[1] NP National Park
WA Wilderness Area
PWA Proposed Wilderness Area
SP State Park
SDA USFS Special Designated Area other than Wilderness Area
NRA National Recreation Area (Ross Lake)
PWR Proposed Wild River
MWS Municipal Water Supply

[2] Insufficient reservoir capacity for developing 1000 mw.

TABLE 12. Potential pumped-storage sites in the Puget Sound Study Area, minimum site capacity 1000 MW .(Cont'd)

No.	Site	Approximate Head, Feet	Maximum Plant Capacity, MW[2]	Special Land Designation[1]
		SNOHOMISH BASIN (Cont'd)		
101	Philippa-Calligan	1,160	3,000	
102	Philippa-Sunday	1,430	2,000	
103	Pratt Lake	1,460	2,000	
104	SMC-Hancock	1,540	6,000	
105	Snoqualmie Lake	1,460	4,000	
106	Snow Lake	2,500	10,000	
107	Twin Lakes	2,890	3,000	
108	Upper Wildcat	2,730	3,000	
		PUYALLUP BASIN		
109	Kapowsin	1,120	1,000	
110	Mowich Lake	2,400	3,000	NP
111	Voight Creek	1,160	3,000	
		WEST SOUND BASINS		
112	Cedar Creek	800	1,000	
113	Hamma Hamma	2,200	3,000	NP
114	Lena Lake	1,200	2,000	SDA
115	Mildred Lakes	3,000	5,000	NP
116	Pine Lake	1,100	2,000	
		NISQUALLY-DESCHUTES BASINS		
117	Beaver Creek	1,100	2,000	
		ELWHA-DUNGENESS BASINS		
118	Hayes-Godkin	1,500	2,000	NP
119	Cox Valley	1,600	1,000	NP

[1] NP National Park
WA Wilderness Area
PWA Proposed Wilderness Area
SP State Park
SDA USFS Special Designated Area other than Wilderness Area
NRA National Recreation Area (Ross Lake)
PWR Proposed Wild River
MWS Municipal Water Supply

[2] *Insufficient reservoir capacity for developing 1000 mw.*

TABLE 13. Site data for pumped-storage sites, Puget Sound Area

No.	Site	Plant Capacity MW	Head Ft.	Penstock Length Ft.	Daily Storage Ac. Ft.	Hydraulic Capacity cfs	Drawdown, Ft. Upper	Drawdown, Ft. Lower	Invest. Cost $/KW	Capacity Cost $/KW-Year
1	Austin	1,000	1,180	5,600	7,400	11,600	92	--	132	7.20
		2,000			14,800	22,200	161	--	119	6.50
2	Bearpaw Mountain	1,000	2,100	15,100	4,600	6,500	46	43	135	7.30
		3,000			13,800	19,600	86	87	107	5.80
3	Blue Mountain	1,000	1,260	3,300	5,500	10,800	43	28	160	8.70
		3,000			16,500	32,300	95	72	124	6.70
4	Bridge Camp	1,000	2,320	8,500	4,000	5,900	40	17	141	7.60
		5,000			20,000	28,400	148	69	98	5.30
5	Chuckanut Mountain	1,000	1,080	7,100	8,300	12,700	76	--	131	7.20
		6,000			49,800	68,500	102	--	98	5.40
6	Dailey Prairie	1,000	2,120	12,200	4,500	6,400	24	27	123	6.80
		3,000			13,500	19,500	59	66	90	4.90
8	Lily Lake No. 1	1,000	2,090	8,400	4,700	6,600	90	--	113	6.20
		2,000			9,400	12,800	139	--	109	5.90
9	Lilly Lake No. 2	1,000	1,520	5,700	7,000	9,000	80	57	123	6.80
		--								
11	Shuksan Lake	1,000	2,850	6,600	3,100	4,800	54	8	112	6.10
		4,000			12,400	18,200	107	26	88	4.80
12	Skagway Pass	1,000	2,520	8,900	3,700	5,400	50	60	120	6.50
		3,000			11,100	16,300	122	114	102	5.50
13	Van Zandt	1,000	1,450	7,000	6,750	9,400	59	28	129	7.00
		--								
14	Washington Monument	1,000	1,570	11,100	6,000	8,700	85	80	141	7.70
		4,000			24,000	33,600	164	72	106	5.80
15	Wickersham Trail	1,000	2,240	8,000	4,200	6,100	67	~1	36	7.40
		2,000			8,400	11,900	84	~2	118	6.40
24	Crystal Lake	1,000	2,680	11,300	3,400	5,100	52	49	124	6.70
		3,000			10,200	15,000	107	79	108	5.90
26	Devils Lake	1,000	840	6,100	10,300	16,400	52	~20	127	7.00
		--								
29	Goat Lake	1,000	920	11,000	10,300	14,900	60	39	151	8.20
		--								
34	Illabot	1,000	2,420	12,500	3,800	5,600	45	55	128	6.90
		3,000			11,400	16,500	89	67	106	5.80
39	Jug Lake	1,000	1,590	8,600	6,000	8,600	74	31	124	6.80
		--								
41	Lower Jordan	1,000	1,750	9,900	5,500	7,800	65	8	110	6.10
		2,000			11,000	15,000	95	16	101	5.50
49	Rinker Ridge	1,000	1,640	8,000	5,800	8,400	69	73	113	6.20
		--								
52	Silver Lake	1,000	1,710	5,600	5,400	8,000	62	52	103	5.70
		--								
57	Watson Lakes	1,000	2,670	8,400	3,600	5,100	24	26	116	6.30
		6,000			21,600	30,900	113	98	89	4.80
58	White Chuck	1,000	3,180	8,400	2,950	4,300	84	32	119	6.50
		--								
60	Ebey Hill	1,000	1,300	3,700	7,600	10,500	61	28	117	6.40
		--								
61	Marten Creek	1,000	1,310	7,600	7,400	10,500	52	23	118	6.50
		3,000			22,200	30,500	64	57	101	5.50
62	Mt. Bullon	1,000	2,160	9,300	3,900	6,300	66	62	122	6.70
		2,000			7,800	12,500	105	109	105	5.70
63	Segelson Ridge	1,000	1,410	7,100	6,750	9,700	46	103	122	6.70
		--								
64	Springsteen Lake	1,000	1,880	7,400	5,600	7,300	105	23	107	5.90
		--								

TABLE 13. Site data for pumped-storage sites, Puget Sound Area (Cont'd)

No.	Site	Plant Capacity MW	Head Ft.	Penstock Length Ft.	Daily Storage Ac. Ft.	Hydraulic Capacity cfs	Drawdown, Ft. Upper	Drawdown, Ft. Lower	Invest. Cost $/KW	Capacity Cost $/KW-Year
66	Tupso Pass	1,000	1,200	5,100	7,900	11,400	101	67	117	6.40
		--								
71	Blanco Lake	1,000	1,980		5,000	6,900	27	76	100	5.50
		3,000			15,000	21,300	80	140	81	4.40
72	Calligan Lake	1,000	1,100	6,600	8,400	12,500	25	31	106	5.80
		10,000			84,000	120,700	170	137	95	5.20
75	Chetwoot Lake	1,000	1,670	9,600	5,500	8,200	45	32	115	6.30
		3,000			16,500	24,700	118	66	89	4.90
80	Francis Lake	1,000	2,240	5,000	4,300	6,100	87	53	115	6.20
		2,000			8,600	12,100	154	88	100	5.40
81	Gifford Lakes	1,000	2,310	6,900	4,000	5,900	32	5-8	114	6.20
		6,000			24,000	33,500	144	24-29	86	4.70
84	Green Ridge Lake	1,000	2,820	8,500	3,400	4,900	51	29	129	7.00
		2,000			6,800	9,600	85	44	105	5.70
86	Hester Lake	1,000	1,370	6,650	6,950	10,000	82	79	115	6.30
		2,000			13,900	19,800	140	118	101	5.50
87	Lake Caroline	1,000	2,800	8,950	3,370	4,900	52	29	121	6.60
		3,000			11,110	14,400	136	78	98	5.30
88	Lake Hancock	1,000	1,050	6,600	8,500	13,000	31	31	116	6.40
		10,000			85,000	127,700	180	82	98	5.40
89	Lake Isabel No. 1	1,000	860	6,100	10,750	16,000	52	38	119	6.60
		4,000			43,000	63,100	149	96	112	6.10
90	Lake Isabel No. 2	1,000	2,120	16,600	4,200	6,500	22	22	130	7.10
		10,000			42,000	62,500	147	113	93	5.00
91	Lake Kulla	1,000	1,740	8,900	5,400	7,900	76	33	106	5.80
		2,000			10,800	15,100	106	48	92	5.10
94	Little Chief Peak	1,000	1,310	5,900	6,950	10,400	66	49	107	5.90
		3,000			20,850	30,300	141	82	91	5.00
95	Loch Katrine	1,000	1,440	7,600	6,200	9,500	75	3-6	105	5.80
		2,000			12,400	18,400	127	7-12	90	5.00
98	Nordrum Lake	1,000	1,940	5,600	4,800	7,100	68	20	100	5.50
		3,000			14,400	20,300	99	69	87	4.70
100	Paradise Meadow	1,000	1,630	4,900	6,750	8,400	72	42	101	5.60
		3,000			17,700	25,400	129	99	88	4.80
101	Phillipa-Calligan	1,000	1,160	8,600	7,900	11,800	62	23	124	6.80
		3,000			23,700	33,500	137	60	104	5.70
102	Phillipa-Sunday	1,000	1,430	9,600	5,900	9,600	48	45	120	6.60
		2,000			11,800	19,100	87	75	108	5.90
103	Pratt Lake	1,000	1,460	7,100	7,000	9,400	74	64	117	6.40
		2,000			14,000	18,500	117	65	102	5.60
104	SMC-Hancock	1,000	1,540	6,250	5,900	8,900	48	12	94	5.20
		6,000			35,400	47,300	159	92	80	4.40
105	Snoqualmie Lake	1,000	1,460	8,000	6,750	9,400	44	51	113	6.20
		4,000			27,000	38,700	129	103	101	5.50
106	Snow Lake	1,000	2,500	8,900	3,700	5,500	22	23	109	6.00
		10,000			37,000	53,800	148	113	83	4.50
107	Twin Lakes	1,000	2,890	8,900	3,400	4,700	41	53	122	6.60
		3,000			10,200	14,300	99	101	100	5.40
108	Upper Wildcat	1,000	2,730	11,300	3,500	5,000	60	22	112	6.10
		3,000			10,500	14,700	137	54	97	5.30
109	Kapowsin	1,000	1,120	8,100	8,300	12,300	17	15	119	6.60
		--								
111	Voight Creek	1,000	1,160	5,600	8,400	11,800	42	47	132	7.20
		3,000			25,200	36,700	76	77	100	5.40

TABLE 13. Site data for pumped-storage sites, Puget Sound Area (Cont'd)

No.	Site	Plant Capacity MW	Head Ft.	Penstock Length Ft.	Daily Storage Ac. Ft.	Hydraulic Capacity cfs	Drawdown, Ft. Upper	Drawdown, Ft. Lower	Invest. Cost $/KW	Capacity Cost $/KW-Year
112	Cedar Creek	1,000	800	3,500	11,800	17,100	76	76	143	7.80
116	Pine Lake	1,000	1,100	11,000	8,600	12,500	89	37	140	7.60
		2,000			17,200	24,100	159	62	132	7.20
117	Beaver Creek	1,000	1,100	4,100	9,400	12,500	46	32	130	7.10
		2,000			18,800	24,800	73	16	106	5.80

Site Selection Criteria and Procedures

Criteria—In selecting the sites to be included in this inventory, the following factors were taken into consideration:

(a) Source of energy
(b) Topography
(c) Operating pattern
(d) Plant size and characteristics
(e) Reservoir size and characteristics
(f) Penstock size and characteristics

Source of Energy—It was assumed that low cost, off-peak energy would be available from thermal plants, and that these plants would be located in or near the Puget Sound Study Area, thus keeping transmission losses from the thermal plants to the pumped-storage plants relatively small.

Topography—The physical characteristics of a site have a direct bearing on the cost of development. To minimize costs, sites were sought which had fairly high heads (600 feet or more), short penstock requirements, and small embankment requirements. By going to higher heads, less water is required per unit of generation, and as a result, it is possible to reduce the costs of the pump-turbine motor-generator equipment, the diameter of the penstocks, and the size of the reservoirs.

Operating Pattern—The operating pattern of a pumped-storage plant will be governed by three interrelated factors: (a) the system load shape, (b) the relative capabilities and economies of the other types of power plants available, and (c) the amount and cost of off-peak thermal energy available for pumping. These factors will change as time progresses, with the situation becoming increasingly favorable for the utilization of pumped-storage as thermal power assumes a larger part of the base load.

It is assumed that the pumped-storage plants will operate on a weekly cycle, generating during the weekday peak hours and pumping during the off-peak hours at night and on week-ends. Studies are now underway which will provide an indication of how pumped-storage will best fit into the future load pattern. Pending the results of these studies, an arbitrary decision was made on the amount of storage to be provided in developing data for project comparison purposes. Sufficient storage was provided to permit generation for eight hours at rated capacity. While it would be possible for such a plant to operate eight hours consecutively at rated capacity, the available night-time pumping energy along with the available reservoir storage would limit this operation. With the available night-time pumping energy and a limited amount of week-end carry-over storage, the project could instead be operated at a variable output equivalent to something less than eight hours at full rated capacity. The plant could thus adapt to a wide variety of loading conditions in the peak portion of the daily load.

An example of one loading condition is illustrated by Figure 14. In this example, the pumped-storage plant is required to operate at full capacity for only a short period each weekday afternoon. For most of the generating period, the plant is operating at less than rated capacity. Thus, the plant is generating the equivalent of approximately 5 hours at rated capacity each weekday. The balance of the storage is used for carry-over of week-end pumping energy until it is required later in the week. The night-time off-peak pumping energy, together with the carry-over week-end storage, is sufficient to provide the storage required to meet the daily peak generation.

It must be recognized that a portion of the conventional hydro capacity available in the regional system will fit only in the extreme peak of the system load. Studies now underway will show how much conventional hydro capacity will fit only in the peak portions of the load and thus determine the optimum

placement of pumped-storage generation. Some of the planned conventional hydro peaking capacity will probably fit only in the peak and force the pumped-storage generation into a lower position than that shown on Figure 14. In the early phases of pumped-storage development, the placement of this "slice" may be such that the plants will be required to generate continuously for more than five hours per day. If this was required, it would be necessary to increase the plant's reservoir capacity. For example, if it were found desirable to operate a pumped-storage plant an equivalent to eight hours at rated capacity five days a week, the plant would require a reservoir capacity about twice as large as a five-hour reservoir. This increase in reservoir capacity would result in a slightly higher investment cost, about $10 to $12 per kw-year. Most of the sites inventoried would be capable of providing this additional reservoir storage.

Plant Size and Characteristics–All sites evaluated are suitable for plants having a capacity of at least 1,000 mw. This minimum size was selected for two reasons. First, the present trend in pumped-storage construction is toward large plants to reduce unit costs. Second, by limiting the sites to a 1,000 mw minimum, it was possible to eliminate the numerous small sites and keep the number of sites under consideration to a workable number. In evaluating the better sites, an attempt was made to derive costs for several plant sizes, up to the maximum feasible installation. The economical advantage of going to the larger installations is illustrated by Figure 15, which shows the relationship of unit cost to installed capacity for a site typical of those located in this survey. The factor controlling the maximum installation was the amount of usable reservoir storage attainable at the site within reasonable draw-down limitations.

The heads available at most of the sites permit the use of reversible Francis pump-turbines. Although present technology limits the design of reversible units being built today to heads of about 1,600 feet, the indications are that reversible units with heads as great as 2,000 feet can be developed by the time these projects would be needed, sometime after 1990. There are a number of sites in the Puget Sound Study Area having heads even higher than 2,000 feet. Based on present technology, these sites would require separate pumps and impulse turbines. The size of the units selected were the largest feasible for a given installation.

Reservoir Size and Characteristics–Reservoir size is governed by the usable storage requirements, the allowable drawdown, and, in the case of the lower reservoirs, the amount of pump-turbine submergence required. The usable storage requirements are a function of the plant capacity and available hydrostatic head (see Figure 16). To keep embankment costs at a minimum, very little dead storage would normally be provided. Hence, the drawdowns necessary to obtain the required usable storage are sometimes quite large. At some sites, however, where it was anticipated that there would be public access to the reservoir, drawdowns were minimized in the interest of safety and aesthetics. For purposes of this study, it was assumed that this would be done either by limiting the capacity of the site or by increasing the dead storage allowance.

Penstock Size and Characteristics–Penstock diameter is dependent on the flow requirement and the maximum allowable velocity. The allowable velocities are based on economic and hydraulic considerations. Preliminary studies indicate that lined tunnels would be more economical than exposed penstocks. The maximum tunnel diameter was set at 40 feet, with multiple penstocks being used where larger flows were required.

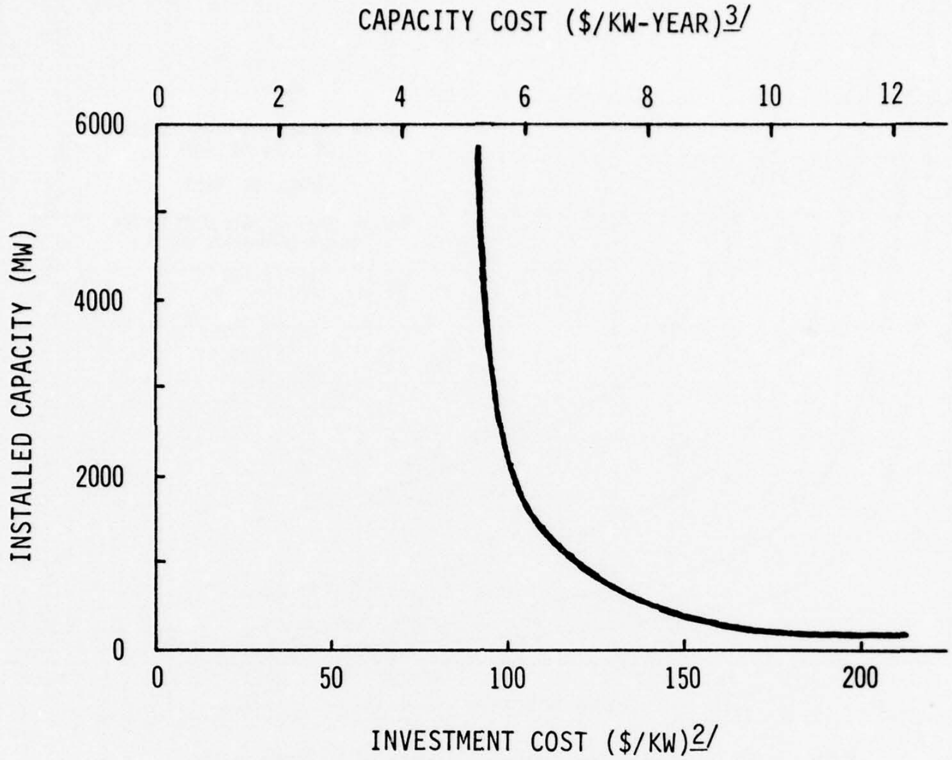
Procedure–The pumped-storage site inventory is based on a map survey. Prospective sites were located using Army Map Service 1:250,000 plastic relief maps and U.S. Geological Survey topographic quadrangle maps. From these maps suitable locations for the upper and lower reservoirs were selected, penstock lengths determined, and storage requirements calculated. Project costs were then determined, and storage requirements calculated. Project costs were then determined based on individual cost calculations made for the following components:

(a) Physical

- (1) Embankment (dams, dikes, reservoirs)
- (2) Relocations
- (3) Powerhouse
- (4) Penstock

(b) Other

- (1) Contingencies
- (2) Engineering & overhead
- (3) Interest during construction
- (4) Operation, maintenance & replacement
- (5) Amortization



1/ Plant having a head of 1500 ft., penstock length of 8,000 ft., and dam and reservoir costs ranging from $5,000,000 for a 250 MW installation to $36,000,000 for a 6000 MW installation.

2/ Includes engineering, interest during construction, and contingencies.

3/ Includes cost of amortizing investment over 50 years at 4-5/8% and estimated operation, maintenance, and replacement costs.

FIGURE 15. Investment and capacity cost vs. installed capacity for a typical pumped-storage plant. 1/

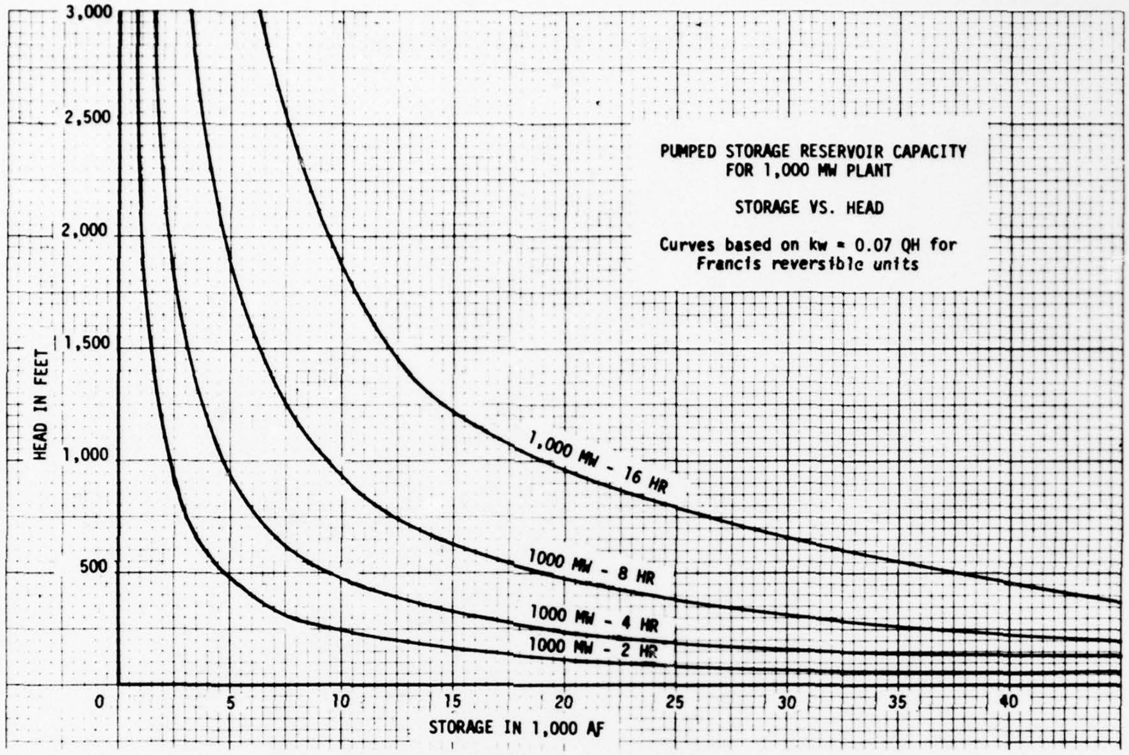


FIGURE 16. Pumped-storage reservoir capacity for 1000 mw plant.

Embankment costs include the costs of earth-filled dams and dikes, outlet works, and intake structures. Relocation costs are included in the total only when significant relocations, such as major highways, were required. Powerhouse costs are based on data for conventional surface powerhouses made available by the Hydroelectric Design Branch of the North Pacific Division, Corps of Engineers. These data were developed for conventional powerhouses; however, where geological conditions permit, savings might be realized by using underground powerhouses. Cost calculations made for sites having heads of more than 2,000 feet have been adjusted to reflect the additional cost of units consisting of a separate pump and turbine connected to a common motor-generator. It was assumed that for plants having heads of greater than 2,000 feet, separate pumping and generating units would be required. Penstock costs are based on a concrete lined power tunnel with bifurcation and a section of steel lining prior to entry into the turbine. All physical costs have been indexed to January 1968. The total investment cost was derived by combining physical costs, contingencies of 25%, engineering and overhead (including contract administration, supervision, and inspection) of 12%, and interest during construction of 4-5/8% over a four-year period. Since it was apparent that there would be many sites available which could be developed at less than $150 per kilowatt, projects having investment costs of greater than $150 per kilowatt were eliminated from further consideration.

The resulting pumped-storage project costs, listed in Table 13, are pure capacity costs. They do not include the cost of pumping energy and may not be compared with alternative peaking sources without the addition of a pumping energy cost. That cost, however, is not site-related. It will be determined by the part of the peak load to be carried by the pumped-storage project and by the source of the pumping energy. Furthermore, in actual system operation, different pumped-storage plants will probably operate at different load factors and will therefore have different return energy requirements. When specific load factor and energy value data becomes

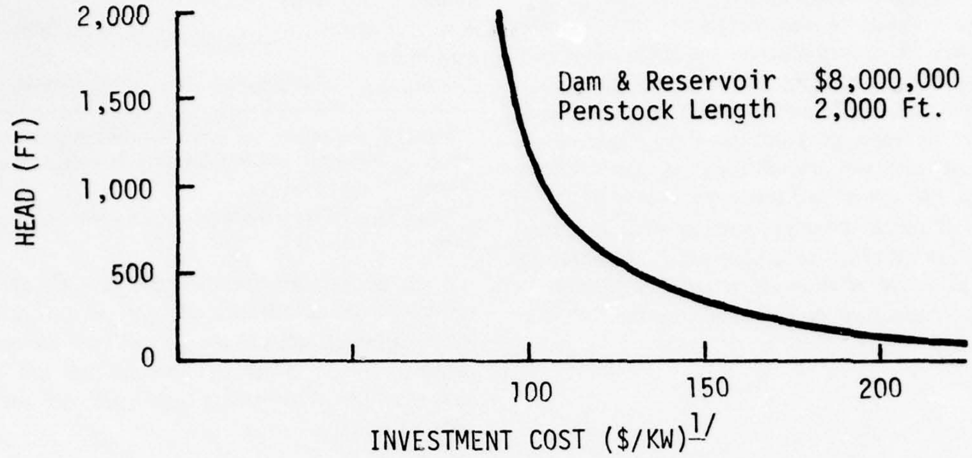
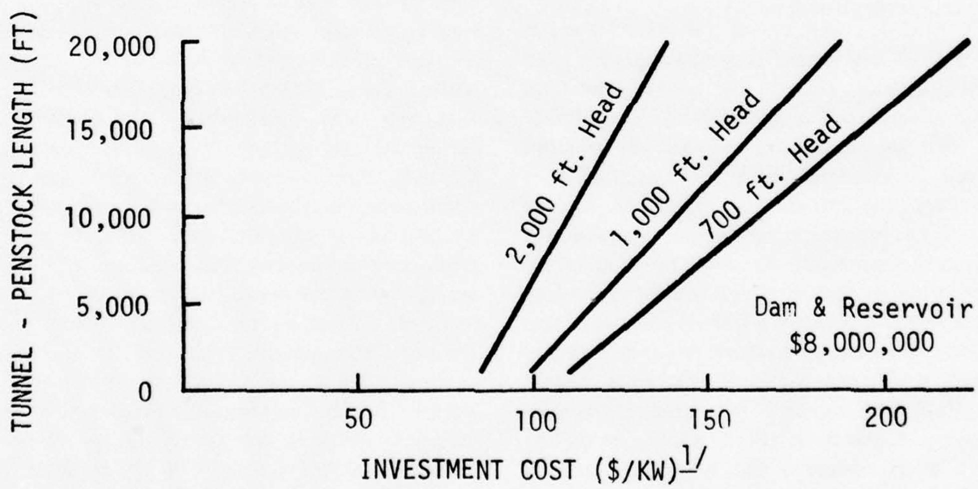


FIGURE 17-A. Investment cost vs. head for 1000 mw pumped-storage plant.



1/ Includes interest during construction and contingencies.

FIGURE 17-B. Investment cost vs. penstock length for 1000 mw pumped-storage plant.

available, the annual capacity costs listed in Table 13 can be used as a basis for computing total annual costs for the individual projects.

As a result of the preliminary site selection studies, certain general observations can be made with regard to the affect of the various site characteristics on capacity costs. The unit cost declines markedly as the head increases as is illustrated by Figure 17-A. The cost increases significantly as the distance between the upper and lower pool increases. This increase is much more pronounced with low head plants than with high head plants as is illustrated by Figure 17-B. The relationship of component costs to the total investment cost is shown by the following table:

Major Components	Percent of Investment Cost[2]
Dams and reservoirs	7%
Powerhouse	38%
Penstocks	20%
Contingencies and other[1]	35%

[1] Includes allowances for contingencies, engineering and design, supervision and inspection, overhead, and interest during construction.

[2] Based on data from the Willamette Basin pumped-storage study.

It can be seen from the table that the dam and reservoir costs constitute a relatively small part of the project physical costs. Taking all of these factors into consideration, it becomes apparent that the better sites would be those having high heads and relatively short penstocks.

GEOTHERMAL POWER

GENERAL DISCUSSION AND BACKGROUND

The earth is a tremendous reservoir of heat but only occasional "hot spots," generally occurring close to volcanic activity, are near the surface. The term "geothermal resource" is generally used to include energy plus any associated mineral commodities which can be extracted from the steam as it is emitted from the earth. Most important, and of greatest current interest, is geothermal electric power which may be generated by releasing steam from naturally hot areas through drill holes and channeling it to a turbine and generating unit. World use of this natural heat as an energy source is relatively new and of limited importance compared with other energy sources. The total capacity of geothermal electric power plants in the world is only about one million kilowatts. It is estimated that this usage can be increased about 10 times under present economic conditions and maintained at that level for at least 50 years (White, 1965, p. 14). The energy produced would be approximately equivalent to that which would be produced by burning one billion tons of coal.

Geothermal energy literally means "earth-heat" energy, and geothermal areas are those areas where the heat is great enough and close enough to the surface to provide a heat source. The heat source will usually be a young, intrusive igneous body, and it must be in or near an area of permeable rocks which contain enough water to transfer the heat along fractures or through drill holes to the surface. An ideal geothermal reservoir is capped by a layer of rock with only slight permeability which inhibits the escape to the surface of hot water or steam. Typically, fluid tapped by drilling will in part flash to steam upon reduction of hydrostatic pressure during its transfer up the well to a power plant. Power production can be commercial if the reservoir is large enough or hot enough to be sustained through recharge. Impurities in the fluid system such as arsenic, boron, and salts must be either low enough in concentration to avoid disposal problems or high enough to be economically recoverable as by-products. Areas in the United States where these conditions exist are located in the Western States, Alaska, Hot Springs, Arkansas, and Hawaii. Such reservoirs exist in the Puget Sound Area but their potential is unknown at present (Wayland, 1966, p. 2).

Italy has 400,000 kw of generating capacity installed in geothermal electric power plants. New Zealand has 250,000 kw in such installations with plans for much more. Mexico has a pilot plant in operation and is planning to build several generating

plants. Geothermal area surveys and exploration have been underway in central Africa since 1955. In Central America, the United Nations organization is sponsoring development of geothermal resources throughout a belt crossing parts of Guatemala, Costa Rica, and El Salvador. A plant has been designed for New Britain Island in the South Pacific and Soviet Union specialists have explored Kamchatka Peninsula in great detail, planning to install several geothermal electrical generating plants there.

Serious interest in geothermal resources began in the United States in about 1955 when the Big Geysers area about 75 miles north of San Francisco was redrilled (McNitt, 1963) (California Legislature, 1967). Four wells with economic potentials began producing at a depth of less than 1,000 feet and, in 1958, the owners of the wells signed a contract to supply steam for electricity to Pacific Gas and Electric Company. Production was started at the Big Geysers in 1960 with installation of 12,500 kw of generating capacity. Plant capacity there is now over 56,000 kw and the entire steam field is estimated to be capable of supporting a plant of more than one million kw.

Status of Geothermal Exploration in Puget Sound Study Area[1]

In general, the geothermal resource potential of the Puget Sound lowland and surrounding mountain area is considered to be moderately favorable relative to the potential of most parts of the United States east of the Pacific rim. Western Washington is in an area of crustal instability and recent volcanic activity. The presence of a few thermal springs notably in the Cascade Range, indicates the possible presence of abnormally high geothermal gradients, perhaps related locally to molten magmas.

Anticipating increased activity in geothermal exploration and development, the U.S. Geological Survey is investigating and designating geothermal areas. A systematic listing of geothermal springs has been made and was published in 1965 as Professional Paper 492 (Waring, 1965) and a tentative classification of geothermal areas has been made which places geothermal resource areas in three categories:

(a) Lands valuable for geothermal resource development.

(b) Lands potentially valuable for geothermal resource development.

(c) Lands valuable prospectively for geothermal resource development.

No lands had yet been found (1966) classifiable in either of the first two categories within the State of Washington. There are, therefore, no public land withdrawals for geothermal energy in the Puget Sound Area. However, there are large acreages of land in category c, principally located near the crest of the Cascade Range. Evaluation of geologic information available at the present time indicates that these, and probably lands elsewhere in the area, may eventually prove valuable for geothermal resource development. The known thermal springs and areas in the Puget Sound Area presently classified as valuable prospectively for geothermal development are shown on Figure 18.

For reasons that are not yet understood, the number of hot springs in the Puget Sound Area is much smaller than in comparable areas in the States currently favored for geothermal exploration, notably California and Nevada. Many springs may represent minor, near-surface "hot springs" from which most of the valuable excess heat is escaping with the hot water. Some hot, warm, or even cool springs, however, may represent minor leakage from deep, large, permeable reservoirs capped by insulating rocks of low permeability (White, 1965, p. 9-10). Such leakage may take place at some vertical and horizontal distance from the reservoir, and the water may have cooled considerably after escaping from the reservoir. In Western Washington, shales, igneous sills, or fine-grained tuffs may form caprocks for sizeable reservoirs in porous rocks such as agglomerates or vesicular or fractured flows. Finding such a reservoir will require careful geological studies supplemented by geophysical data and testing by exploratory drilling.

Because the available facts suggest that any important geothermal reservoirs present in the Area will be deep beneath caprocks, surficial studies such as airborne infrared surveys are considered to be less promising than structural studies and geologic projections aided by penetrative geophysical techniques. One type of geophysical project that could be profitably undertaken in the Area would be to make geothermal gradient and heat flow measurements in existing or new, deep, cored wells in or near areas of Pleistocene and Recent volcanism. Bottomhole temperatures are usually obtained when electric and

[1] From an article by Russell G. Wayland for which publication was authorized by the Director, U.S. Geological Survey, March 3, 1966.

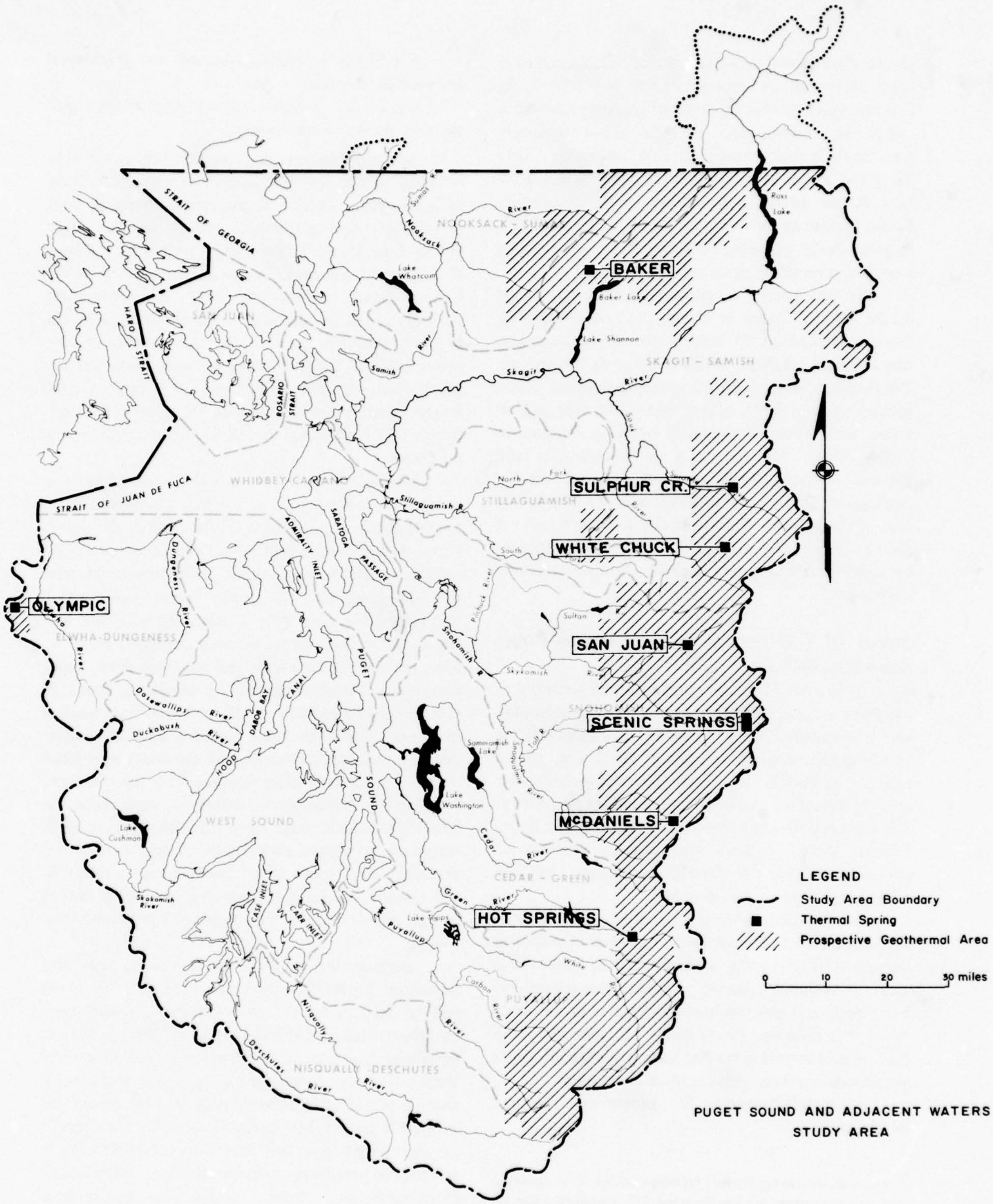


FIGURE 18. Thermal springs and prospectively valuable geothermal areas.

radioactive logs of holes drilled for oil and gas are made. These temperatures could be collected from all logs made in Western Washington. Discovery by this means of high geothermal gradients would narrow the target for exploratory drilling.

SUMMARY

Current interest in geothermal resources is centered around its use as a source for electric power. World use of the resource for this purpose now equals about one million kw. Estimates are that the use can be increased ten-fold under present economic conditions and maintained for at least 50 years. Areas of greatest use are in Italy, New Zealand, and Iceland; but other countries are carrying out investigations in an effort to locate and develop geothermal resources. In the United States areas of indicated geothermal value are principally in the 11 Western States and one field, Big Geysers in California, is being successfully developed.

The Puget Sound Area has few thermal springs but does have relatively large areas near the Cascade rim and probably elsewhere which warrant study as prospectively valuable geothermal development sites. If, however, the northwest alone will require 95 million kw of power at peak loading by the year 2000, as estimated by Luce (1964), even the discovery of several sizeable capped geothermal reservoirs in the Puget Sound Area will still leave the Area largely dependent upon other sources of energy.

FOSSIL-FUEL ELECTRIC PLANTS

Hydroelectric power has been more economical than fossil-fuel power in the Puget Sound Area. Essentially all of the head which can economically be harnessed for hydroelectric energy production has already been or will be developed in the next decade. Therefore, the Area will obtain capacity to supply peak demands by adding generating units at some existing hydroelectric plants both within and outside the Study Area, and by the construction of pumped-storage projects and fossil-fuel steam-electric generating plants. The fossil-fuel plants designed for peaking could be coal, oil, or natural gas-fired steam-electric plants, gas-turbines, and diesel-engine generating installations.

BASE LOAD

There are about 2.0 billion tons of coal reserves in the Puget Sound Study Area. However, much of the coal in the Area is not mineable at present economic rates. The cost of transporting coal fuels from outside the Area could be a deterrent to the construction of large base-load fossil-fuel steam-electric plants in the Area.

PEAKING

Gas turbines using the combined cycle can be designed to operate efficiently burning natural gas or distillate oil. Gas turbine generators possess many features which make them desirable for certain types of power system duty. They have a low installed cost, quick start-up, require few auxiliaries, and can be made semi-automatic in starting and stopping which minimizes need for attention from operating personnel. They can be located with considerable freedom, since their cooling water requirements are small and they are not dependent on any single fuel source. Maintenance costs are low because of simple, compact construction with all parts readily accessible. Gas turbine electric generators are ideal for peaking service, but much too expensive to operate at high capacity factors for base load use, due to relatively high heat rates (Btu/kwh).

Diesel-engine driven generators have an advantage serving small loads where quick starting, dependability, and minimum need for supervision by operators are of primary importance. This makes them desirable for "end-of-line" parts of a power system during peak load periods, when the voltage in such a section would otherwise sag badly. They are commonly used as the entire source of power for small, isolated loads.

SUMMARY

Gas turbines are preferable in some applications to conventional steam peaking capacity. They have the advantage of short lead-time, low capital cost, and no low cooling water requirement. Fuel costs are of

importance to fossil-fuel-fired plants, much more so to plants operated in base-load than to peaking plants which require much smaller annual quantities of fuel. Oil for use in any type of power plant–steam, gas turbine, or diesel engine–now costs over 40 cents per million Btu with little apparent likelihood that this cost will come down. This is not a severe handicap, however, for a peaking duty thermal plant, since fuel use by such a plant is relatively low. Therefore, some fossil-fuel peaking plants may be built in the Puget Sound Study Area; but, none are presently scheduled.

NUCLEAR ELECTRIC PLANTS

In less than thirty years the application of nuclear energy for electric power generation has evolved from the laboratory into commercial use. This evolution took place under extreme difficulty considering such a complex technology. Emerging into a well established field of keen competition in methods of electric power generation, competition from nuclear plants has contributed to major reductions in the price of coal and coal transport and has stimulated improvement in other alternative power generating sources.

The demonstration that nuclear power is practicable and reliable is sufficient to assure its utilization in applications which take advantage of one or both of its two most important unique qualities. These are the ability to produce large quantities of electricity from a very small although expensive fuel inventory, and to operate without requiring combustion air which avoids releasing large quantities of pollutants to the atmosphere. These attributes alone will not assure extensive use of nuclear energy as a means to produce electricity for the power industry in the foreseeable future. For wide use, in the Puget Sound Area, nuclear power must offer electricity at a cost lower than other alternative sources.

Like conventional fossil-fuel-fired steam-electric plants, nuclear power plants use heat to produce steam to drive turbine generators. The major difference is that conventional steam-electric plants use heat produced by combustion of fossil-fuel in a furnace; and nuclear plants use heat produced by fission of nuclear fuels in a reactor. Basically, a nuclear reactor performs the same functions as a fossil-fuel furnace and boiler. Shielding for the reactor must be provided to contain hazardous radiationduring normal operation. Special containment facilities and other safeguards must be incorporated to prevent the escape of radioactive material in the unlikely event of a reactor accident. For these and other reasons, a nuclear plant will usually have higher construction costs than a fossil-fuel plant. However, the capital cost estimates per kilowatt of capacity in nuclear plants have declined even more rapidly than in fossil-fuel plants with each increase in unit size. Accordingly, the capital cost disadvantage of nuclear plants in comparison with conventional steam-electric plants is less significant for plants with larger units.

The fund requirements for a nuclear fuel inventory is considerably larger than for a fossil-fuel inventory for a conventional steam plant. The important consideration is that the total cost of fuel, including all inventory charges as well as material, processing and handling costs, be included as a part of the total plant generation costs. The major financial difference between nuclear fuel and fossil-fuel is the timing and magnitude of cash flow.

A more specialized operating staff organization is required for nuclear than for fossil-fuel-fired power plants. Accordingly, nuclear plants have been relatively more expensive to operate and maintain than conventional plants. However, this difference is expected to decline with increasing nuclear plant capacity and greater operating experience. A present-day nuclear power plant with 1,000 mw electric power output employing a light water reactor produces about 3,070 mw of total heat. The thermal efficiency typical of such a system is 32.6 percent. Efficiencies of 40 percent or better are not anticipated until high temperature gas cooled reactor systems become available commercially, probably in the middle 1970's. This data is for present reactor development. Fast breeder reactors, also more efficient than light water reactors will probably not come into commercial use until the late 1980's.

The means of condensing steam exhausted from the turbines is the same for both conventional fossil-fuel steam plants and nuclear steam plants.

Water, the usual coolant pumped through the condenser, absorbs heat given up by the condensing steam.

Present turbine-generators in nuclear power plants can be designed to operate with a condensing temperature of about 90 to 95°F. This relatively low temperature heat has no present market and is, therefore, wasted.

HEAT DISSIPATION SYSTEMS

Siting of thermal plants will require explicit evaluation of the heat dissipating impacts on the local environment. Special studies of environmental impact are being made of potential sites in the marine waters of the Puget Sound Area. Heat dissipation systems applicable for use with large nuclear power stations are once-through cooling, evaporative, and dry exchange systems.

Once-Through Cooling Systems

Power plants using these systems need a large water supply, therefore, they are located along rivers, lakes, and tidewaters. Water is pumped through condensers, absorbs heat, and is returned to the source. Once-through cooling systems are usually the simplest and least expensive when sufficient cooling water is available. The dissipation heat rate from a 1,000 mw nuclear power plant of 7 billion British Thermal Units per hour requires about 1,600 cfs (cubic feet per second) or 720,000 gpm (gallons per minute) to limit the coolant temperature to a maximum rise of 20°F. The cost of a fresh water once-through system will normally total 4 to 5 percent of direct construction costs for the plant as a whole. Salt water systems cost more due to the expense of non-corrosive materials, water treatments, and other facilities. Once-through cooling is least expensive to install. However, due to the Water Quality Standards set by the Federal Government and the State of Washington, which set temperature control requirements on interstate, intrastate and coastal waters, other types of cooling must be considered. Several of these are discussed and compared with once-through cooling.

Evaporative Cooling Systems

Some plant locations may not have an adequate water supply for once-through cooling. Temperature requirements of Water Quality Standards, excessive costs due to pumping, or other restrictions may also rule out the use of a once-through system. Normally, the alternative choice of cooling is by an evaporative type system, through the use of natural or induced draft cooling towers, cooling ponds, or spray ponds. These systems cool the recirculating water primarily by evaporation, augmented by convective transfer of heat to the atmosphere, and, in some cases, by radiation of heat. Evaporative cooling systems require much less water than once-through systems. The water make-up requirements for a 1,000 mw nuclear power plant may range from 25 to 100 cfs. These systems virtually reject the entire heat load to the atmosphere rather than to bodies of water, thus apparently circumventing thermal effects on water quality or aquatic life.

Compared to once-through cooling systems, the evaporative systems have several disadvantages. These systems require increased capital expenditures and pumping power costs. They usually have higher condenser temperatures which lower the capacity and efficiency of the turbines. Water consumptively used causes the plant to compete with water use for irrigation, municipal, industrial, and other demands.

The operation of a cooling tower or pond may introduce unwelcome atmosphere conditions, such as fogging or "drizzle" downwind of the plant. Disposing of "blowdown" flows from the system could impose a problem. This blowdown flow consists of about 1 to 4 cfs of water burdened with dissolved solids, both naturally occurring substances in highly concentrated form and chemicals added for required treatment of the water system.

Natural Draft Cooling Towers—(See Figure 19). These systems utilize the density difference between the heated, essentially saturated air within the tower, and the atmospheric air surrounding the tower, to establish and maintain circulation of air through the structure. The major structural feature of a natural draft tower is a tall, hollow hyperbolic shell which acts as a chimney and creates a draft for air circulation. The actual cooling function takes place in the lower part of the tower. These towers are quite large (approximately 400 feet high and 400 feet in base diameter). A 1,000 mw nuclear plant would require two towers, each having a design flow of about 300,000 gpm and a heat load of 3.6 billion Btu/hr. The annual average evaporation rate is about 32 cfs. If such a plant were operated at 100 percent plant factor, the total water consumptive use due to evaporation would be about 23,000 acre-feet per year.

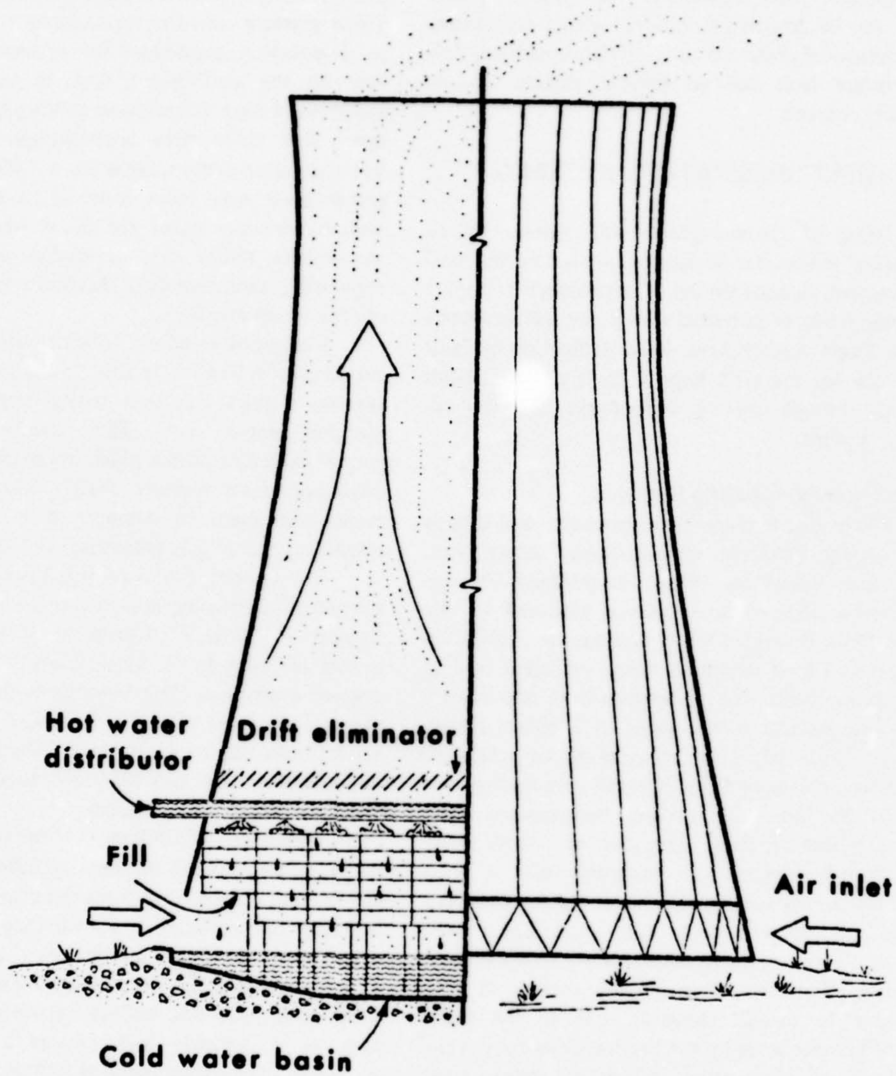


FIGURE 19. Natural draft tower. Wet type (evaporative) counterflow.

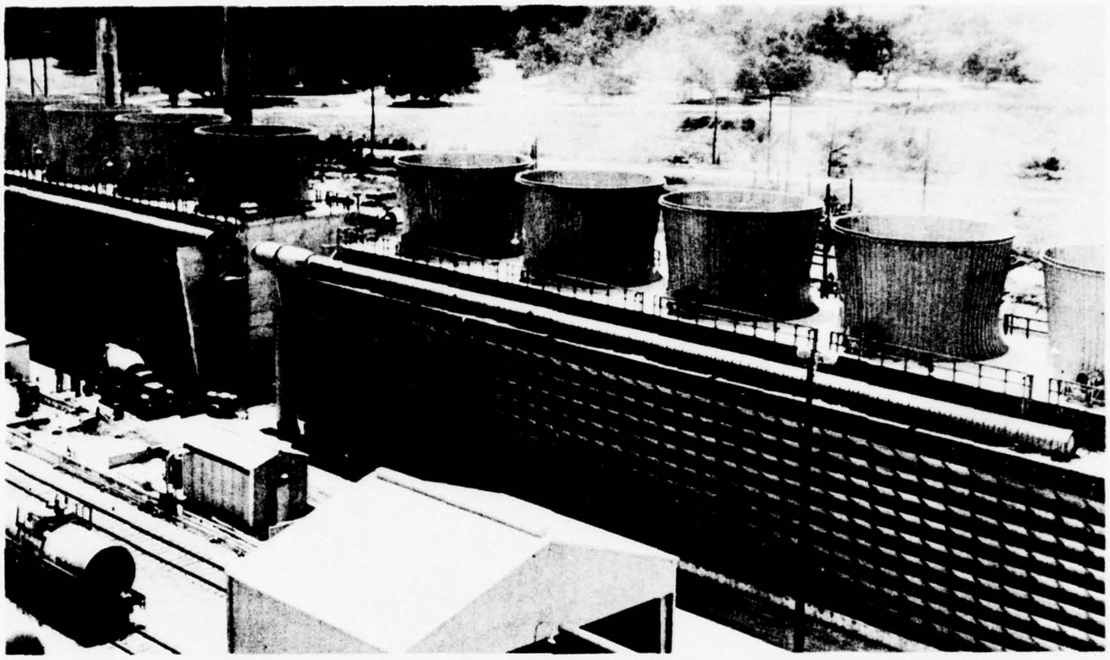


PHOTO 6. Two induced draft cooling towers, cross flow, wet type.

Induced Draft Cooling Towers–Systems with induced draft cooling towers perform the same function as natural draft systems, but in a different manner. They house the packing and water distribution systems; a large propeller-type fan in the top of a tower cell draws air in through the packing and exhausts it above the tower cell. The available capacity of a single fan limits the cell size from about 35 to 80 feet on a side and from 20 to 60 feet high. A 1,000 mw nuclear power plant might contain 32 to 36 cells, widely spaced to minimize air recirculation, covering a ground area some 320 by 1,200 feet in extent. A plant of this size would require about 4,800 horsepower for fan operation.

The installation costs for an induced draft system are considerably less than for a natural draft system for a 1,000 mw plant. The direct construction cost of about $4 million is about half that of a natural draft system. However, operating and maintenance costs are considerably higher. These towers are also more apt to cause ground fogging and "drizzle" in the vicinity of the plant than the natural draft towers with their high level discharge.

Cooling Ponds

At sites with available land and favorable terrain, the cooling pond method may be considered. With suitably flat land, a pond can be constructed merely by inclosing it with earth dikes; or an existing lake, or river flood plain may be utilized as a cooling pond. A pond capable of serving a 1,000 mw nuclear power plant would require about 2,000 acres of surface area with a depth from 15 to 20 feet. The exact amount of surface area would depend upon climatic conditions, such as local winds and humidity.

A cooling pond must be sized to dissipate not only the heat removed from the condensers, but also the heat of sunlight incident to the pond. For a pond large enough to serve a 1,000 mw plant, the solar thermal load may equal or exceed that imposed by the plant. Seepage may also cause a loss of water. Both of these effects add to the consumptive use of

water by a cooling pond. The solar effect will, in warm summer weather, approximately double the evaporation rate of water as compared to a cooling tower: from 25-30 cfs to 50-60 cfs.

Spray Ponds

This type of cooling may considerably reduce the amount of surface area needed in a pond, since the hot water is sprayed into the pond through a system of nozzles. The cooling occurs while the water falls through the air. A spray pond is actually an intermediate case between a cooling pond and cooling tower. This type of cooling is subject to a high windage loss of water. Spray ponds may be an attractive cooling device for smaller heat loads but not for large nuclear power plants.

Hybrid Cooling Systems

When river flows are marginal for once-through cooling or thermal restrictions are imposed on plant effluents so that through cooling would be operable for only part of the year, a hybrid system which combines two types may be necessary. In such cases, it might be desirable to install an evaporative system sized to full plant capacity for operation only when once-through cooling could not be used. The capital cost of the hybrid system would be equal to or greater than a full-scale evaporative system. Operating costs would be lower.

Water-To-Air or Steam-to-Air Heat Exchange Systems

These cooling systems have certain advantages in that the circulating water system need not be separated from the condensate system and the condensate pumped directly to the tower. Convective exchange only, dissipates the heat. Natural draft or forced draft towers may be used. With condensate quality water used throughout the system, problems of scaling, corrosion, and fouling of heat exchange surfaces are minimized. This type of system consumes very little water, often a vital consideration in

PHOTO 7. A thermal plant using a Hybrid cooling system.

water-short areas. Water treatment costs may be reduced.

However, the cost of the extensive power piping and extended surface construction (finned tubing, etc.) required for dry exchange systems may be four to five times that of an evaporative system. For a 1,000 mw nuclear power plant, the cost of such a system would be prohibitive for any normal situation. Such a system would be considered only when sufficient water is unavailable for operation of other types of cooling systems.

LAND AREA REQUIRED FOR NUCLEAR POWER DEVELOPMENT

Federal regulations and other considerations establish the minimum required site area. A 1,000 mw light water moderated nuclear power plant site will need a minimum exclusion area having a radius of 3,000 feet. This area must be owned and controlled by the plant owner. The area required for the nuclear plant site would contain about 650 acres, plus easements and access rights-of-way. For waterfront sites, the required land area will approximate a semi-circle of some 325 to 350 acres. A site on a peninsula may require a much smaller area. The exclusion area may vary in shape from site to site depending upon local terrain, prior subdivisions, and the inclinations of the owners. The water exclusion area will be subject to restrictions, the same as the land exclusion area.

USES OF EXCLUSIVE ZONE UNOCCUPIED BY NUCLEAR POWER PLANT FACILITIES

Federal regulations specifically permit traversing the exclusion zone of a nuclear power plant by highways, railroads, or waterways. Activities unrelated to operation of the reactor may be permitted in an exclusion area under appropriate limitations, provided that no significant hazards to the public health and safety will result. The owner may, with Federal approval, allow agriculture, compatible industries, hunting and fishing, and even picnicking in the exclusion area providing there are no overnight facilities. Arrangements must be made for radiation monitoring, evacuation, etc.

MULTIPLE-UNIT DEVELOPMENT OF NUCLEAR POWER PLANTS

The decision of where to locate the next large generating station presents one of the most challenging problems any electric utility faces when planning to add capacity to obtain a power supply at the lowest cost. Factors considered include distribution of load, load growth, existing and prospective patterns of loading of the transmission system, interconnections with other systems, availability of land, foundation conditions, availability of usable cooling water, and growing concern with atmospheric problems from cooling facilities.

The number of good sites available for large thermal generating stations decreases with the increase in population, expansion of the economy, and the more active interest of the general public, as well as the State and local public agencies, in community matters. The interests of an electric utility and its customers can best be served by constructing the largest, economically justified generating plant complex on each site selected. The handicap of rigorous site requirements in some locations could be overcome, at least to a degree, by building several reactor units on a single site. This assumes that the individual reactors are provided with safeguards so that an accident with one would not violate the integrity of the containment system of the whole nuclear complex. Experts in reactor design predict that by 1985, units of 3,000 mw will be in use in multi-unit plants containing three or four units. An exclusion area not much larger than that provided for a single reactor probably would suffice. Unit costs could also be reduced by use of a reactor fuel handling and maintenance facility common to all units, and by the use of a common control system.

Fully utilizing the multi-unit approach could result in a very large capacity nuclear station. The capital cost outlay could be shared by several utility systems and result in the establishment of a nuclear generation center. While such a development would reduce the number of nuclear plant sites and conserve valuable land, the economies of construction and operation would have to be balanced against the cost of transmitting power from such a single large source throughout a large market area rather than from several strategically located and dispersed smaller

sources. However, a large capacity transmission grid would tend to minimize unit transmission costs and by so doing result in additional potential savings in customer power costs.

OPERATION AND COSTS OF NUCLEAR POWER PLANTS

Nuclear plants built in the Puget Sound Area can be expected to operate at relatively high capacity factors of 80 to 85 percent, since this manner of operation takes the greatest advantage of the plants' low energy costs. However, experience with existing operating plants elsewhere in the United States has shown that nuclear plants can follow load variations, i.e., be operated at low capacity factors of 40 to 60 percent if necessary.

The capital and operating costs of nuclear plants determine whether or not such plants are economically competitive with other types of thermal power plants. Nuclear plants (perhaps even more than fossil-fuel steam-electric plants) with the larger size units tend to cost less per kilowatt. For example, two existing nuclear plants, both of the 50-60 mw size, cost over $400 per kilowatt to build. Larger nuclear plants in the 200 mw range have been constructed at about one-half the cost. In the period 1975-1980, new nuclear plants most likely will be composed of much larger units (at least 1,000 mw), and a capital cost, based on 1968 price levels, ranging from $160 to $200 per kilowatt, depending upon site related factors, method of cooling, and other considerations.

POTENTIAL AND FUTURE TRANSMISSION FACILITIES

PRESENT PLANNING AND DEVELOPMENT

At present, with an essentially all-hydro system, approximately 65 percent of the load requirements for the Puget Sound Study Area are transmitted from hydroelectric generation sources east of the Cascades. As the transition to a thermal-electric base progresses, thermal plants located within or adjacent to the Study Area will meet more and more of the Area's load requirements. However, these will be primarily base-load plants, with peak requirements supplied by hydroelectric plants east of the Cascades. This means construction of new transmission lines to the east with attendant increases in needs for rights-of-way land. Some additional north-south lines will be needed to provide integration and bulk-load power transfers within the Study Area and with adjacent load areas. Figure 20, "Major Transmission Facilities, Puget Sound Study Area 1990," illustrates possible transmission development for the Study Area by 1990. Present plans call for the construction of several of these lines at voltage levels in excess of 500 kilovolts (kv).

Right-of-Way and Circuit Planning

The land required for electric power transmission has been a problem, not only in areas of concentrated population, but through rural, forested, recreation, and other areas as well. However, as transmission voltages increase, the land use per kilowatt for transmission right-of-way decreases. For example, a 500 kv alternating-current line can carry more than four times the power of a 230 kv alternating-current line. Yet, the 500 kv line requires only slightly more right-of-way. Studies have been made which show that it would be feasible to replace some of the existing 230 kv lines with planned 500 kv circuits, utilizing the same general right-of-way which would result in reducing the need for new right-of-way.

By 1980, there will be in operation, planned, or under construction, some 480-circuit miles of 500 kv lines in the Puget Sound Study Area. The line routings involved are: from Olympia to Blaine (via Kent, Monroe, and Arlington); from Vantage to Kent; and from Chief Joseph Dam to Monroe. The right-of-way land requirements for these lines would approximate 9,200 acres within the Study Area, if new rights-of-way are required for all of these lines. However, portions of the new lines will be routed over existing rights-of-way presently occupied by 230 kv lines which will be retired. This will reduce the additional land requirement by some 1,700 acres in the Area.

Additional 230 kv transmission lines in the Puget Sound Study Area are also planned. These lines will be utilized as integrating lines within the Area and as subtransmission for customer service.

Whatever future land requirements may

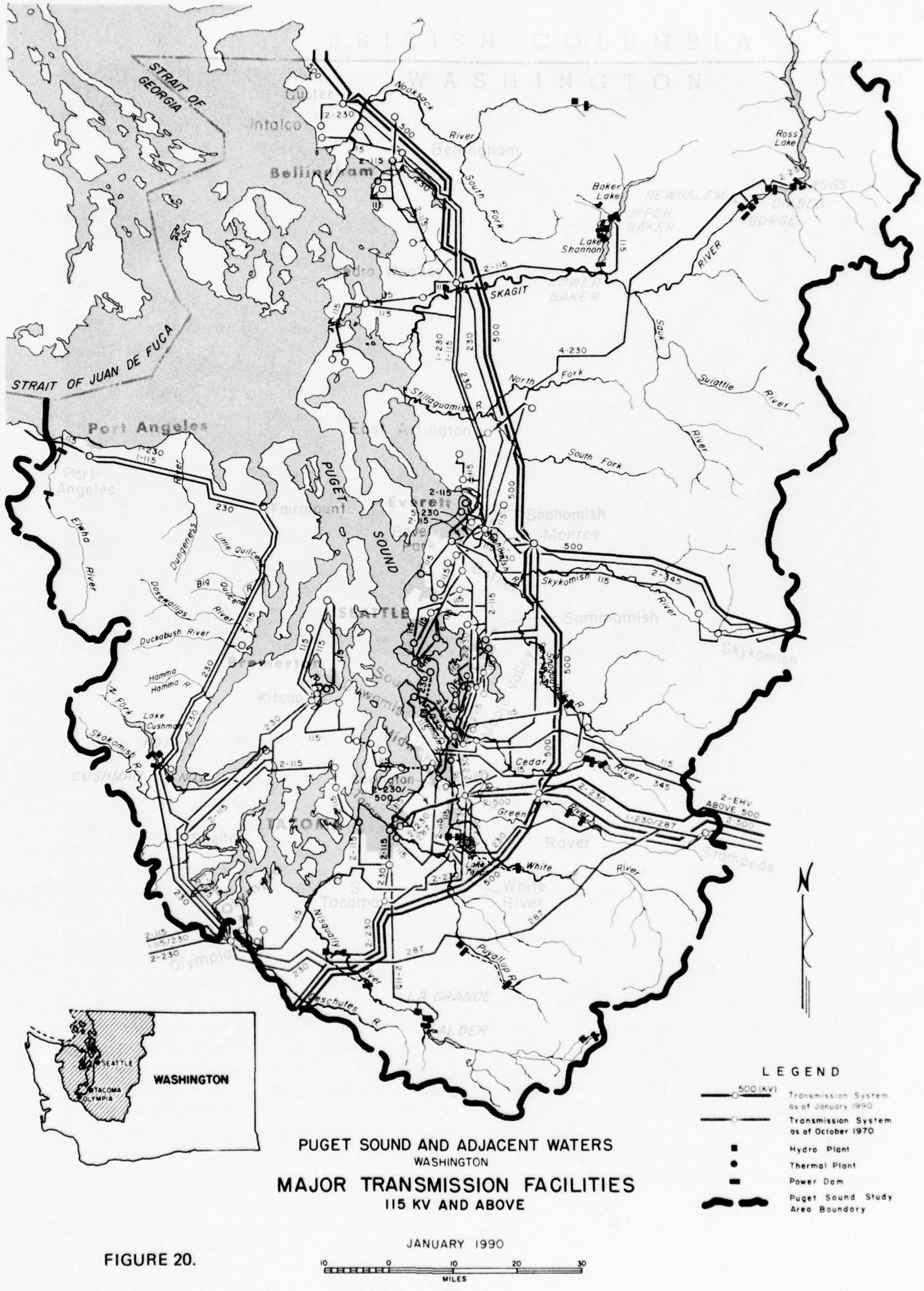

BRITISH COLUMBIA
WASHINGTON
STRAIT OF GEORGIA
STRAIT OF JUAN DE FUCA
PUGET SOUND
Bellingham
Port Angeles
Everett
SEATTLE
Bremerton
TACOMA
Olympia
Intalco
Custer
Fairmount
Snohomish
Monroe
Kitsap
S. Tacoma
Ross Lake
Baker Lake
Lake Shannon
NEWHALEM
UPPER BAKER
LOWER BAKER
DIABLO
GORGE
CUSHMAN
LA GRANDE
ALDER
Nooksack River
South Fork
SKAGIT RIVER
Sauk
Suiattle River
North Fork
South Fork
Stillaguamish R.
Skykomish River
Skykomish
Sammamish
Snoqualmie R.
Cedar River
Green River
White River
Puyallup R.
Nisqually River
Deschutes R.
Elwha River
Dungeness
Little Quilcene
Big Quilcene R.
Dosewallips River
Duckabush River
Hamma Hamma R.
N. Fork
Lake Cushman
Skokomish R.
Raver
Stampede
2-EHV ABOVE 500
N
SEATTLE
TACOMA
OLYMPIA
WASHINGTON
PUGET SOUND AND ADJACENT WATERS
WASHINGTON
MAJOR TRANSMISSION FACILITIES
115 KV AND ABOVE
JANUARY 1990
10 0 10 20 30
MILES
LEGEND
500 (KV)
Transmission System as of January 1990
Transmission System as of October 1970
Hydro Plant
Thermal Plant
Power Dam
Puget Sound Study Area Boundary

FIGURE 20.

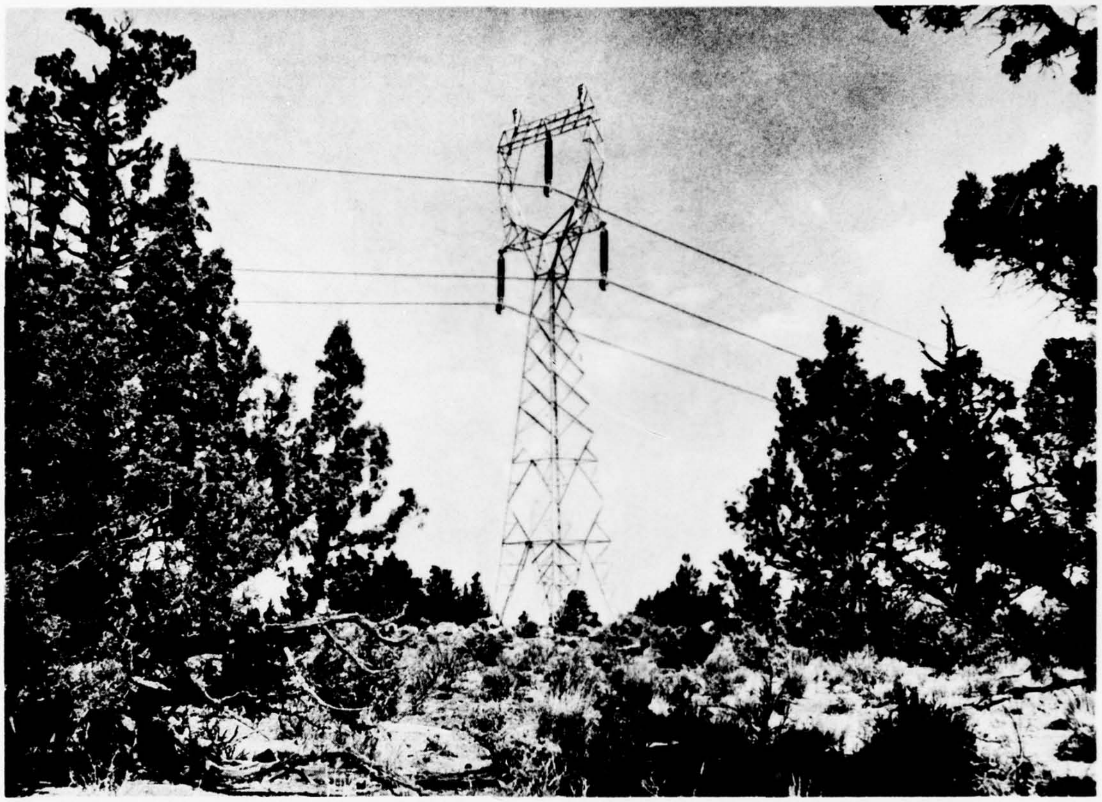


PHOTO 8. 500 KV transmission line (USBPA Photo)

develop, the need for careful placement of transmission corridors in respect to other forms of land use will continue. Where possible, planners will route transmission lines through areas which have the least conflict with other land uses. Farm or pasture lands, brush areas, etc., adapt well for transmission line use with minimum conflict. Also, transmission line planners should consider the aesthetic distraction of line locations in certain areas and avoid public recreation areas, main highway routes, or wilderness type vista areas where possible.

Replacement of existing lines with higher-voltage higher-capacity lines will reduce new right-of-way requirements. However, continually increasing power requirements in the Puget Sound Area will require still more transmission capacity between the large generating complexes east of the Cascades and this area. By the fall of 1970, two 500 kv lines will interconnect these areas in addition to the existing 230, 287, and 345 kv system. North-south lines will also tie this area with the Willamette Basin area. By 1980, the equivalent of seven 500 kv lines will be needed in the Area, and by 1990, an equivalent of nine 500 kv lines will be necessary. Competing needs for land use will, no doubt, preclude the construction of this many trans-mountain lines to the Study Area. In addition, the total exceeds the estimated capacity of the available mountain pass routes. Clearly, other measures for providing the necessary transmission capacity are required, such as increasing the capacity per circuit or developing new methods of electric transmission.

One alternative under serious study is that of going to voltage levels in excess of 500 kv. Several 700 kv class lines are in operation or under construction at the present time in this and other countries. Since a 700 kv line has approximately twice the capacity of a 500 kv line, use of this voltage level as an overlay to the extensive 500 kv grid being developed would reduce the number of circuits required and the impact on land use in the Study Area.

RESEARCH AND DEVELOPMENT

Studies are also progressing on 1,000 kv transmission facilities. A 1,000 kv line has approximately four times the capacity of a 500 kv line. Use of this voltage level may reduce the total number of lines required still further. However, reliability considerations dictate an orderly strengthening of the system (in the Puget Sound Area at 500 kv) before going to the higher voltage. The higher the line capacity, the greater the impact on the system when that line is lost due to a short circuit or some other contingency. Further studies are necessary to determine the optimum level of voltage for the circuits comprising the next grid overlay, both from a technical and an economic standpoint.

The laying of underground cable on existing rights-of-way presents another technically feasible method of increasing the transmission capacity per right-of-way. However, this method costs 10-25 times as much per kw of power transmitted as standard overhead lines. Research continues because in certain areas, such as large metropolitan centers, underground transmission is the only method acceptable. Here, transmission distances are short and the increased costs have much less impact than a 100-300 mile transmission distance would impose.

Direct-Current Transmission

Direct-current transmission may be employed for large-block power transfers within the Pacific Northwest in future years. At the present time, direct-current can compete economically with alternating current transmission only when distances are greater than approximately 500 miles for overhead lines and 30-60 miles for underground cables. Direct-current terminals are quite complex and costly when compared with a-c substation equipment, but d-c line costs are only about two-thirds that of alternating current. The economic "crossover point" occurs when the difference in line costs equals the difference in terminal costs. Since the average transmission distance within the Northwest for future systems will be less than 300 miles, direct-current will have no economic benefit unless marked reductions in terminal costs are effected. Of course, if other factors require the use of underground cables, direct-current could be very attractive.

Another factor which could influence the use of d-c transmission is the magnitude of fault duties on terminal equipment as the system grows. As a-c facilities are added, short-circuit quantities increase with resultant greater stresses imposed upon circuit breakers and other electrical equipment. This could cause a rather expensive equipment change-out program. The use of d-c system additions rather than a-c would obviate this need, since fault duties are not increased by the addition of d-c facilities.

The cryogenic field may accelerate the use of d-c transmission with the development of superconducting cables having many times the capacity of conventional lines or cables. By refrigerating the conductors to temperatures near absolute zero, a system can attain transmission of power essentially without losses, thus allowing very high power flows per circuit. Even though the cost per circuit would be high, the unit cost per kilowatt transmitted could be quite low.

Research is progressing on superconductors, but thus far no significant breakthroughs have resulted. One interesting facet of this program is the possible development of an ambient-temperature superconductor. Success in this effort would revolutionize the whole field of power transmission.

TRANSMISSION AND NUCLEAR POWER DEVELOPMENT

Thermal plants will in general be located adjacent to or near the major load centers to minimize transmission costs, both in facilities required and in transmission losses. Of course, a number of other factors will influence plant location. Among these are environmental and geologic considerations and the desire of the constructing agencies for locating thermal plants within their service areas.

Studies based upon transmission considerations alone have been made for determining the optimum scheduling and location of these plants through the 1985 period. Results indicate that the preponderance of the thermal plant additions up to this time should be located west of the Cascades and south of the Puget Sound Area. Power normally flows to the west and south in the western portion of the Northwest grid. The Portland area is approximately 100 miles farther from the large mid-Columbia generating complex than the Puget Sound Area. In effect, locating a plant in the Portland area rather than in the Puget Sound Area would save approximately 100 miles of transmission line plus resultant line losses. This pattern would continue during the early period of thermal additions only. When the north-south flows

on the coastal grid are reduced to low values, the distribution of new thermal plants will follow the load growth pattern. By 2000, as much as 10,000 mw to 15,000 mw of new thermal generation may be located within the Study Area.

SUMMARY

Providing sufficient rights-of-way for the transmission of large amounts of power presents one of the biggest problems of the power utilities in the Northwest by the year 2000 and beyond. This will be particularly true for the movement of power from the area east of the Cascade Mountains to the load centers west of these mountains. The major share of the Northwest power requirements is concentrated in the large population centers of the Pacific slope. This situation will continue throughout the period of this study. Load forecasters estimate an increase in the Pacific Northwest load from about 18,000 mw (18,000,000 kw) in 1970, to approximately 90,000 mw in 2000, with 28,000 mw of this total in the Puget Sound Area. (See Table 15, Electric Power Requirements in the Puget Sound Area). Local thermal generation will meet most of this increase. However, large-block, extra high-voltage power transmission from other areas will probably supply the remainder.

By 1990, (see Figure 21, Power Supply Load Areas and Transmission Routes), when essentially all of the feasible hydro sites in the Northwest will have been developed, loads will have grown to more than triple 1970 levels. This will require additional transmission capacity of more than twice that constructed during the previous twenty-five years.

Future transmission lines must have markedly greater power transmission capacities per right-of-way to reduce their impact on land use and remain within the limits of available rights-of-way. Increasing transmission voltage levels provides one method of accomplishing this, since line capacity increases approximately as the square of the voltage.

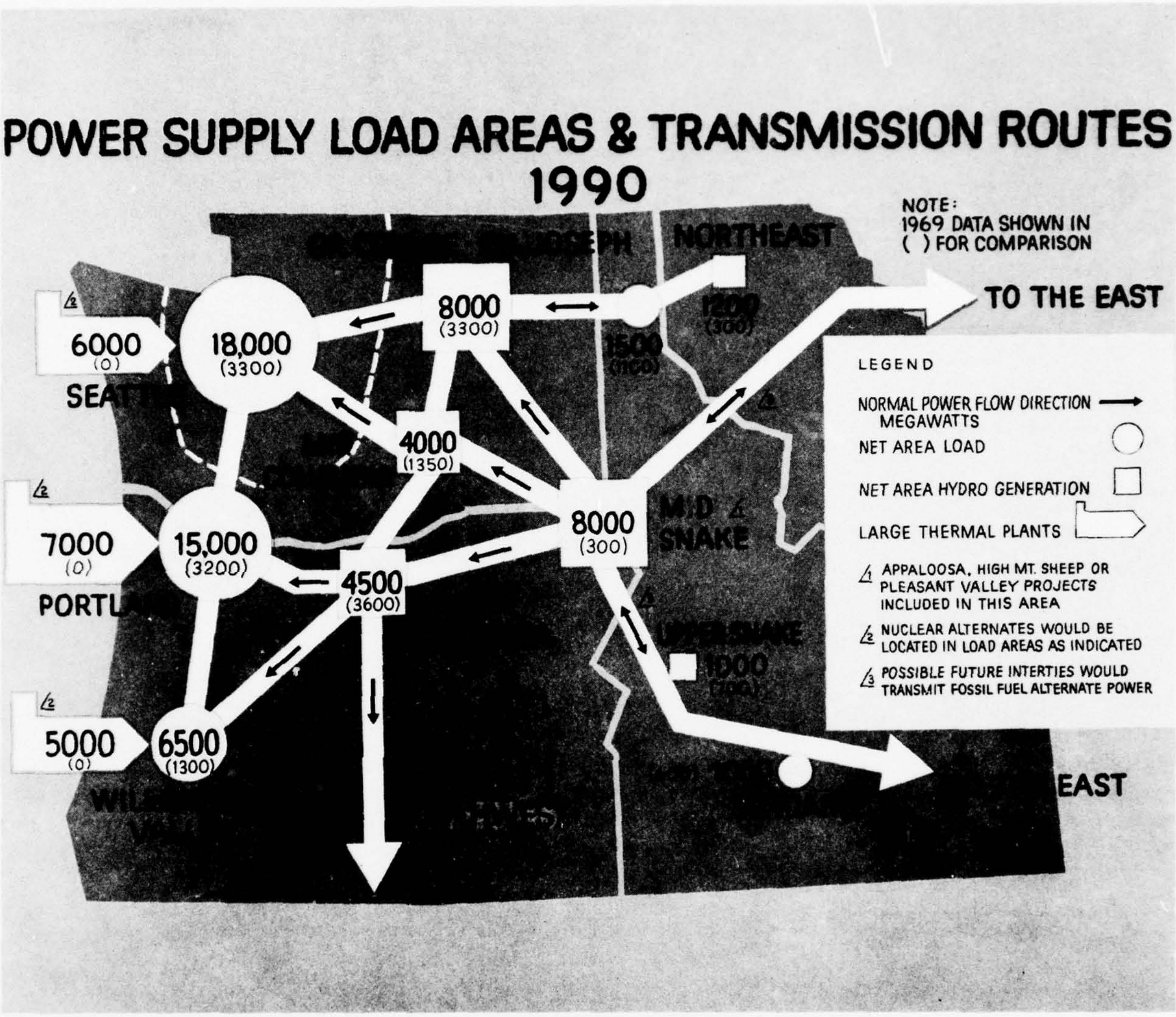


FIGURE 21. Power supply load areas and transmission routes 1990.

FUTURE ELECTRIC POWER REQUIREMENTS IN THE PUGET SOUND AREA

Area power requirements will increase from 17.4 billion kwh in 1965 to 48.3 billion kwh by 1980. In the year 2020 power requirements will have increased to 400 billion kwh. This represents an overall 55-year annual rate of growth of 5.9 percent during the 1965-2020 period of forecast. Figure 22 illustrates the projected growth.

BASIC ASSUMPTIONS

Population will grow from 1,877,000 in 1965 to 2,727,000 by 1980 in the Puget Sound Area. This is at an annual rate of increase of 2.5 percent. By 2020 the population will be 6,809,000. During the 1965-2020 period the annual rate of growth will be 2.4 percent.

Industrial growth, including expansion in the aerospace and electroprocess industries will provide greater employment opportunities in the Puget Sound Area. This growth will also assure an expansion and greater employment potential in the service industries.

The regional wholesale electric power costs will continue at lower than national average costs as an inducement to industry. Future power will be generated, in part, from higher cost steam turbine generators. Both fossil-fuel-fired plants and nuclear power plants will contribute to the regional power supply. The blending of hydroelectric power with steam generation will result in a continuing lower local average wholesale power cost compared with the national average.

ENERGY LOADS BY CONSUMER CLASSIFICATION

The forecast power requirements reflect a steady growth in sales to all major consumer classifications.

DOMESTIC

Ratios between population estimates and domestic customers have been developed to 1980 based on historical trends. Kwh use per domestic customer reflects primarily a substantial increase in the number of homes with electric heat to justify the forecast use by 1980 of 17,400 kwh per customer. During the mid-1960's less than 2 in 10 homes had electric heat in Washington. By 1980 over 4 in 10 will have electric heat installations. Estimates of major appliance saturations are shown in Table 14.

Figure 22

PUGET SOUND AREA
ELECTRIC ENERGY REQUIREMENTS

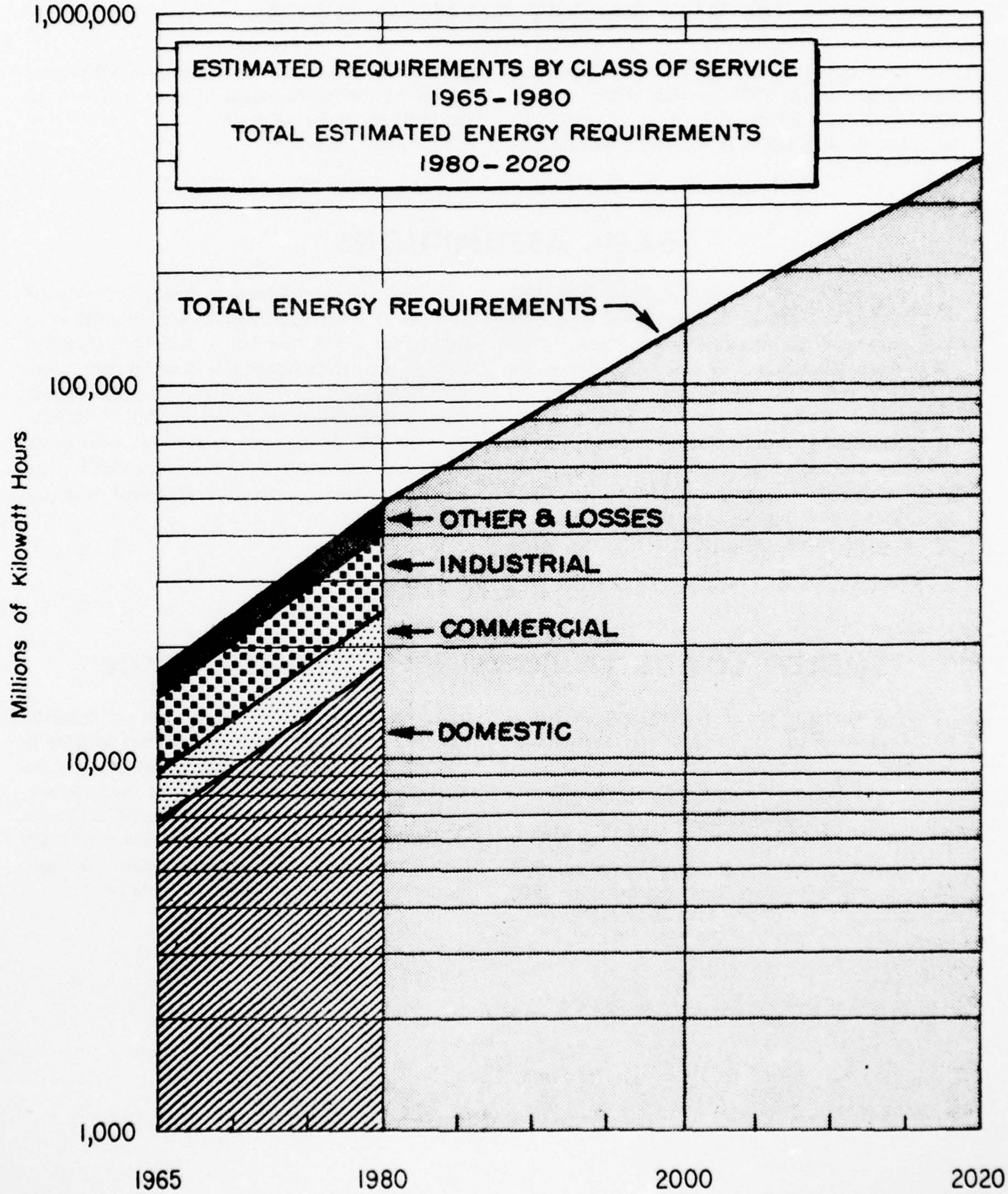


TABLE 14. Estimated contribution of selected appliances to total residential average use

Appliances	Percent Saturation*	Appliance Average Annual KWH Use	Contribution to Total Average Use
	YEAR 1960		
Electric heat	12%	11,000	1,320
Water heater	82%	4,500	3,690
Range	84%	1,400	1,180
Automatic laundry	53%	1,000	530
Freezers	26%	900	230
Other			2,379
Total Use			9,329
	YEAR 1980		
Electric heat	45%	12,000	5,400
Water heater	86%	5,500	4,730
Range	89%	1,400	1,250
Automatic laundry	75%	1,000	750
Freezers	32%	1,600	510
Other			4,760
Total Use			17,400

*Ratio of homes with stated appliance to total number of homes.

Source: 1960 data from U.S. Census of Housing.

COMMERCIAL

Ratios between estimated population and number of commercial customers have been developed to 1980 based on historical trends. Average annual use per commercial customer will grow from 37,918 kwh in 1965 to 71,000 kwh by 1980.

Commercial customers will require more electricity to satisfy greater demands for improved lighting, electric heating, and air conditioning, as already evidenced in the newer shopping centers. Records for the number of commercial establishments now having electric heat installations are not available but evidence of a widespread and growing use exists. Competition will require modernization of existing commercial establishments.

INDUSTRIAL

No ratios between population and industrial customers were developed. There is little reliability on the number developed and no assurance on the size of the industrial plants.

Average kwh use per industrial customer is of dubious value in forecasting. Total sales for this category were developed based on potential growth of industries likely to expand or initially operate in the Area. Approximately 38 percent of total kwh sales will be to industrial customers by 1980.

IRRIGATION

Irrigation sales have been less than 1 percent of total sales historically. Future sales will be greater but still will constitute less than 1 percent of total sales.

OTHER

Street lighting, public authorities, and military establishments are included in this category. Less than 4 percent of total sales are in this category. Sales will grow from 568 millions kwh in 1965 to 1,530 millions kwh in 1980.

LOSSES AND ANNUAL LOAD FACTORS

Losses consist of transmission, transformation, and distribution losses, and energy unaccounted for between sources of supply and delivery points. Losses as a percent of energy requirements have been declining during the past decade in the Puget Sound Area. This is consistent with the electric utility industry experience in general. By 1980 losses are estimated at 10 percent.

Annual load factors have averaged 57 percent since 1960 within a range of 50-59 percent. This is the ratio of the average hourly electric power requirement during the year to the maximum hourly demand. The low occurred in 1964 during an extreme temperature deviation. There is less than a 1 percent probability of this occurrence based on 60 years of temperature data. Adjusting this year to near normal, the 1960-1965 load factor would average 58 percent in the Puget Sound Area. This load factor was used for the period of forecast.

TOTAL MONTHLY AND ANNUAL LOADS

Estimates of power requirements beyond 1980 are shown for the years 2000 and 2020. Growth rates paralleling the Pacific Northwest area forecast used by the Pacific Northwest Utilities Conference Committee were used as guidelines in the extension to the year 2020. Utilities with generation submitted their load estimates through 1985-1986. Load levels forecast by the utilities in the Puget Sound Area are reflected in 1980. The above-mentioned committee in extending the forecast beyond the original 20-year period agreed to a declining rate of growth of 1/4 of 1 percent each decade through the year 2020. This declining rate was used in extending the Puget Sound Area load forecast to 2020. However, the Puget Sound Area power requirements are forecast to grow at a faster rate than the Pacific Northwest region. The declining rate was applied to the higher Puget Sound Area growth rate in the extension. As indicated by Table 16, the result was an overall growth rate of 5.9 percent during the 1965-2020 period. The Pacific Northwest growth rate for this same period is 5.3 percent in the PNUCC forecast. Table 15 shows the electric power requirements for the Puget Sound Area for the years 1965, 1980, 2000 and 2020.

TABLE 15. Electric power requirements in the Puget Sound Area 1965-2020

	Actual	Forecast		
	1965	1980	2000	2020
Population (000)	1,877	2,727	4,300	6,809
Ratio population/domestic customers	3.0/1	2.6/1		
Domestic customers	626,157	1,046,000		
KWH use per customer	11,052	17,400		
Total domestic use GWH*	6,920	18,200		
Ratio population/commercial customers	28.3/1	26.5/1		
Commercial customers	66,240	103,000		
KWH use per customer	37,918	71,000		
Total commercial use GWH	2,512	7,311		
Industrial customers	2,395	--		
Total industrial use GWH	5,432	16,404		
Irrigation sales GWH	9	25		
Other GWH	568	1,530		
Total sales GWH	15,441	43,470		
Losses	1,966	4,830		
Total requirements GWH	17,407	48,300	142,500	400,000
KWH per capita	9,274	17,700	33,100	58,700
Peak MW (December)	3,453	9,500	28,100	78,800
Annual load factor	57.5%	58%	58%	58%

*Gigawatt-hours (millions of kwh).

Source: Population data from Economic Work Group of PS&AW Task Force. Power data from BPA office records.

TABLE 16. Compound annual rates of growth

Years	Puget Sound Area	Pacific Northwest
1955-1965	5.6%	5.6%
1960-1965	6.9%	6.5%
1965-1980	7.0%	6.5%
1980-2000	5.6%	5.1%
2000-2020	5.3%	4.8%
1965-2020	5.9%	5.3%

Source: Computed from Table 15 and PNUCC report.

For comparative purposes, Table 16 shows annual rates of growth for electric power requirements in the Puget Sound Area and the Pacific Northwest. The anticipated greater rate of growth in the Puget Sound Area, when compared with the region, reflects the expansion in the aerospace and electroprocess industries.

PEAK

Puget Sound Area monthly peak capacity and average energy load patterns were constructed by using the index shown in Table 17. This index is based on monthly load patterns developed by the major utilities in the Area and used in the current PNUCC report.

TABLE 17. Monthly index

	Peak Capacity	Average Energy
January	95.3%	115.3%
February	89.5%	111.3%
March	84.7%	106.6%
April	80.2%	98.3%
May	73.1%	90.3%
June	69.9%	86.3%
July	66.8%	83.0%
August	69.0%	86.2%
September	74.0%	91.8%
October	82.6%	100.5%
November	94.7%	111.1%
December	100.0%	119.1%
		100.0%

Source: PNUCC report.

The monthly index was used for the years 1980, 2000 and 2020 in Table 18 to show monthly peak and average Area requirements.

ENERGY

It should be noted that Table 18 shows average monthly Area loads in thousands of kilowatts using the index shown in Table 17. If energy requirements in kwh are required, the figures would have to be multiplied by the hours in the month.

TABLE 18. Future electric power requirements, Puget Sound Area (megawatts)

	1980		2000		2020	
	Peak	Average	Peak	Average	Peak	Average
January	9,050	6,340	26,800	18,760	75,100	52,690
February	8,500	6,120	25,100	18,120	70,500	50,870
March	8,050	5,860	23,800	17,340	66,700	48,720
April	7,620	5,410	22,500	15,990	63,200	44,930
May	6,940	4,970	20,500	14,690	57,600	41,280
June	6,640	4,750	19,600	14,050	55,100	39,450
July	6,350	4,570	18,800	13,510	52,600	37,940
August	6,560	4,740	19,400	14,030	54,400	39,400
September	7,030	5,050	20,800	14,940	58,300	41,950
October	7,850	5,530	23,200	16,350	65,100	45,940
November	9,000	6,110	26,600	18,080	74,600	50,780
December	9,500	6,550	28,100	19,380	78,800	54,440
		5,500		16,270		45,700

Source: Indices in Table 17 applied to data in Table 15.

VALUE OF POWER

INTRODUCTION

The benefits of power produced by a conventional or pumped-storage hydroelectric project are equivalent to the value of the power to the users as measured by the amount they would be willing to pay for such power. Normally, the cost of power from the most likely alternative source is an appropriate measure of the value of the power produced by a project.

The value of power can be expressed in two components–capacity value and energy value. The capacity value is derived from a determination of the fixed costs of the selected alternative source of supply. The energy value is determined from those costs of the alternative which relate to and vary with its energy output. The fixed costs are those annual costs governed by the investment in generating and transmission facilities, their appropriate financing charges, and certain other operating costs which vary very little with hours of operation. The energy value is determined from the cost of fuel consumed and operation and maintenance costs which vary with energy output. The capacity and energy components are usually expressed in terms of dollars per kilowatt-year and mills per kilowatt-hour, respectively. The capacity component is related to the dependable capacity of the hydroelectric plant and the energy component to the average usable energy output of the plant.

The value of hydroelectric power can be estimated for either or both of two locations: (1) at-market, i.e., at a load center; or (2) at-site, where power leaves the hydroelectric plant.

The alternative to a hydroelectric project is the most likely power supply source that normally would be selected for addition to the regional power supply if the project is not constructed. At the present time the most likely alternative is a modern thermal-electric generating plant. The proper type of thermal plant alternative is the one which will provide the most economical source of peaking, intermediate, or base load service in the absence of the hydroelectric plant expected to be used for any one of these types of service. No values based on a coal-fired steam-electric power plant were estimated since, under present circumstances, it does not appear that additional plants of this type will be constructed west of the Cascades, after the Centralia plant is completed.

In estimating power value, consideration must be given to differences in dependability between the project and its alternative. Differences in operating flexibility, service availability and fast loading features which stem from plant characteristics need to be considered. These characteristics include the low speeds and temperatures of the rugged hydro plant machinery in contrast to high speed, high temperature and pressure of high efficiency thermal plants. Usually, consideration of these factors will indicate that a credit to the value of hydroelectric project plant capacity is warranted. Estimates of this credit vary from 5 to 15 percent of the at-market cost per kilowatt of alternative thermal capacity.

Power values derived herein are based on present day (January 1, 1969) price levels, and are applicable to those hydroelectric sources projected to be constructed in the three study periods–1980, 2000 and 2020.

POWER VALUES BASED ON TYPES OF ALTERNATIVE POWER PLANTS

The three types of thermal-electric plants considered appropriate as alternatives to hydroelectric projects with annual capacity factors ranging from 1 to 90 percent are as follows:

Type of Plant	Hydro Plant Capacity Factors (Percent)
Gas Turbine	1 to 10
Steam-electric peaking	2.5 to 30
Nuclear-electric	20 to 90

Although each plant has an assigned band of capacity factors, in actual practice not every one of them would be operated over the full band owing to design and operational constraints and economic considerations.

The description of these plants is given in Table 19. The capital costs include all costs of a modern thermal-electric plant as constructed. Plant designs include features for minimizing production of pollutants and wastes which have adverse effects on the environment.

Table 20 shows costs of thermal power at the generator bus, at-market and the at-site values of hydroelectric project power for ranges of capacity factors. Power values include a credit of 10 percent to cover the advantages of hydro capacity discussed previously. The estimates of project plant at-site power values were obtained by deducting from the at-market values a hydro plant average Pacific Northwest transmission liability of $2.25 per kilowatt-year, a 4.5 percent capacity loss, and an energy loss which varies with the annual capacity factor.

Costs and values were estimated based on both private and public non-Federal construction of the alternatives. Private power costs assume that the financing will be with a money cost of 7 percent. The financing of public non-Federal alternative sources is assumed to be at an interest rate of 4.75 percent. The total annual fixed charge rates for plants, substations, and transmission lines vary not only with the type of financing but also with estimated service lives, interim replacement costs, insurance, and taxes. Values developed for both types of financing permit the evaluation of power benefits at projects which may be constructed to supply either a public or a private market. For a particular hydro project's output, the appropriate value should be the lower of the values shown for the annual capacity factor at which the hydroelectric plant is expected to operate.

In addition, composite at-market and at-site values are shown. They were developed by weighting the private and public non-Federal values on the basis of the present division in Pacific Northwest power supply which is split between public and private approximately 3 to 1. The resultant values permit power benefits to be computed for those projects which are expected to supply a mixed private and public market. Thus, one type of financing is not favored to the exclusion of the other.

Composite at-site values, i.e., with both the capacity and energy components included, are given in mills per kilowatt-hour in Table 21 and plotted on Figure 23. Also shown in Table 21 is a range of capacity factors and corresponding values. The curves and the uniform values are appropriate for estimating at-site power benefits of hydroelectric projects which may supply a mixed private and public non-Federal market as in the Puget Sound, Willamette River Basin, or Columbia-North Pacific areas of the Pacific Northwest, but excluding the predominantly private system market of the middle and upper Snake River Basin.

TABLE 19. Pacific Northwest description of thermal-electric plants (alternatives to hydroelectric plants with specific ranges of capacity factors, January 1969 price levels)

Item	Type of Plant: Gas-turbine Peaking	Steam-electric Peaking	Nuclear-electric
Capacity factor Range in percent	1-10	2.5-40	20-90
Total capacity, MW	640	800	2,000
Units: Number	4	2	2
Size, MW	160	400	1,000

Item	Type of Plant: Gas-turbine Peaking	Steam-electric Peaking	Nuclear-electric
Capital cost, $/KW	77	82	159
Fuel: Type	Oil	Oil	Nuclear
Average fuel cost, $/million Btu	0.88	0.452	0.12[1]
Average net heat rate Btu/kwh	16,500	11,078	10,500[2]

[1] Equivalent to a nuclear fuel cost of 1.23 mills/kwh (5 fuel cycle average) and a net plant heat rate of 10,500 Btu/kwh (with turbine rating at design back pressure of 1.8"-2.0" Hg).

[2] For comparison only with conventional steam-electric plants. Nuclear plant efficiency in Btu/kwh not normally specified since it is not relevant in computations of fuel energy costs.

Source: Federal Power Commission.

TABLE 20. Pacific Northwest values of hydroelectric plant power based on unit annual costs of power from alternative thermal sources (January 1969 price levels)

Item	Gas-Turbine Peaking Plant: Annual Capacity Factor (Percent)	Capacity: Private Financing $/KW-Year	Capacity: Public Non-Federal Financing $/KW-Year	Energy Mills/KWH	Composite Values: Capacity $/KW-Year	Composite Values: Energy Mills/KWH
Cost of Power at thermal plant generator bus	1.0	8.71	6.08	20.88	--	--
	2.5	8.78	6.14	17.49	--	--
	5.0	8.86	6.19	16.10	--	--
	7.5	8.94	6.25	15.65	--	--
	10.0	9.01	6.30	15.42	--	--
Value of hydroelectric power at market	1.0	11.91	8.45	20.96	9.32	20.96
	2.5	11.99	8.51	17.57	9.38	17.57
	5.0	12.08	8.57	16.19	9.45	16.19
	7.5	12.17	8.64	15.75	9.52	15.75
	10,0	12.24	8.69	15.52	9.58	15.52
Value of hydroelectric power at site	1.0	8.80	5.49	20.77	6.32	20.77
	2.5	8.87	5.55	17.38	6.38	17.38
	5.0	8.96	5.61	15.99	6.45	15.99
	7.5	9.04	5.67	15.52	6.51	15.52
	10.0	9.11	5.72	15.27	6.57	15.27

Source: Federal Power Commission.

TABLE 20. Pacific Northwest values of hydroelectric plant power based on unit annual costs of power from alternative thermal sources (January 1969 price levels) (Cont'd)

Item	Oil-Fired Steam-Electric Peaking Plant					
	Annual Capacity Factor (Percent)	Capacity: Private Financing $/KW-Year	Capacity: Public Non-Federal Financing $/KW-Year	Energy Mills/KWH	Composite Values: Capacity $/KW-Year	Composite Values: Energy Mills/KWH
Cost of power at thermal plant generator bus	2.5	10.43	7.63	5.83	--	--
	5.0	10.90	8.10	4.71	--	--
	7.5	11.33	8.52	4.31	--	--
	10.0	11.65	8.83	4.10	--	--
	15.0	12.22	9.38	3.91	--	--
	20.0	12.66	9.81	3.80	--	--
	25.0	13.01	10.15	3.76	--	--
	30.0	13.40	10.52	3.80	--	--
Value of Hydroelectric power at market	2.5	14.76	10.77	5.88	11.77	5.88
	5.0	15.30	11.32	4.76	12.32	4.76
	7.5	15.79	11.79	4.36	12.79	4.36
	10.0	16.16	12.16	4.15	13.16	4.15
	15.0	16.81	12.78	3.97	13.79	3.97
	20.0	17.31	13.28	3.87	14.29	3.87
	25.0	17.71	13.66	3.83	14.67	3.83
	30.0	18.15	14.08	3.88	15.10	3.88
Value of hydroelectric power at site	2.5	11.52	7.71	5.82	8.66	5.82
	5.0	12.03	8.23	4.70	9.18	4.70
	7.5	12.50	8.68	4.30	9.64	4.30
	10.0	12.85	9.03	4.08	9.98	4.08
	15.0	13.48	9.63	3.90	10.59	3.90
	20.0	13.95	10.10	3.79	11.07	3.79
	25.0	14.33	10.47	3.75	11.43	3.75
	30.0	14.75	10.87	3.79	11.84	3.79

Source: Federal Power Commission.

TABLE 20. **Pacific Northwest values of hydroelectric plant power based on unit annual costs of power from alternative thermal sources (January 1969 price levels) (Cont'd)**

		Nuclear-Electric Plant				
		Capacity			Composite Values	
Item	Annual Capacity Factor (Percent)	Private Financing $/KW-Year	Public Non-Federal Financing $/KW-Year	Energy Mills/KWH	Capacity $/KW-Year	Energy Mills/KWH
Cost of Power at thermal plant generator bus	20	22.86	16.75	1.44	--	--
	30	22.88	16.77	1.37	--	--
	40	22.93	16.82	1.34	--	--
	50	22.97	16.86	1.32	--	--
	60	23.05	16.94	1.31	--	--
	70	23.10	16.99	1.30	--	--
	80	23.20	17.09	1.29	--	--
	90	23.35	17.24	1.29	--	--
Value of hydroelectric power at market	20	29.08	21.38	1.46	23.31	1.46
	30	29.11	21.41	1.39	23.34	1.39
	40	29.16	21.46	1.36	23.39	1.36
	50	29.21	21.52	1.34	23.44	1.34
	60	29.29	21.60	1.33	23.52	1.33
	70	29.35	21.66	1.33	23.58	1.33
	80	29.46	21.77	1.32	23.69	1.32
	90	29.63	21.93	1.32	23.86	1.32
Value of hydroelectric power at site	20	25.19	17.84	1.43	19.68	1.43
	30	25.22	17.87	1.36	19.71	1.36
	40	25.27	17.92	1.32	19.76	1.32
	50	25.32	17.97	1.30	19.81	1.30
	60	25.39	18.05	1.29	19.89	1.29
	70	25.45	18.11	1.28	19.94	1.28
	80	25.56	18.21	1.27	20.05	1.27
	90	25.72	18.36	1.27	20.20	1.27

Source: Federal Power Commission.

TABLE 21. Pacific Northwest composite hydroelectric plant power values at site[1] (January 1969 price levels)

Thermal Source (Hydro Plant Alternative)	Annual Capacity Factor (Percent)	Total Value[2] Mills/ KWH
Gas turbine	1.0	92.92
	2.5	46.51
	5.0	30.72
	7.5	25.43
	10.0	22.77
Steam-electric (peaking)	2.5	45.36
	5.0	25.66
	7.5	18.97
	10.0	15.47
	15.0	11.96
	20.0	10.11
	25.0	8.97
	30.0	8.30
Nuclear-electric	20.0	12.66
	30.0	8.86
	40.0	6.96
	50.0	5.82
	60.0	5.07
	70.0	4.53
	80.0	4.13
	90.0	3.83

Annual Capacity Factor (Percent)	Uniform Value[3] Mills/ KWH
1.0	92.90
2.5	45.40
5.0	25.70
7.5	19.00
10.0	15.50
15.0	12.00
20.0	10.10
25.0	9.00
30.0	8.30
40.0	7.00
50.0	5.80
70.0	4.50
90.0	3.80

[1] *Appropriate for determining power benefits of hydroelectric projects which may supply a mixed private and public market.*

[2] Total values derived from composite at-site capacity and energy components of value given in Table 20.

[3] Taken from curves shown on Figure 23.

Source: Federal Power Commission.

FEDERALLY FINANCED RIVER DEVELOPMENT PROJECTS

The evaluation of power benefits at Federal river development projects is guided by Senate Document No. 97 which was prepared under the direction of the President's Water Resources Council. The Document provides that where benefits are measured by alternative costs, as is the case for power, the alternative cost will be based on the alternative means that would most likely be utilized to provide equivalent product or services. In the Pacific Northwest where no Federally financed thermal plants are planned, this most likely alternative has been considered to be a composite of private and public non-Federal thermal plants described in the preceding section.

The Document provides, however, that in formulating projects, benefits and costs shall be expressed in comparable quantitative economic terms to the fullest extent possible. Generation costs at a Federal hydroelectric project in the Pacific Northwest must therefore be less than power generated at a Federally-financed thermal plant if the project is to be proposed for construction.

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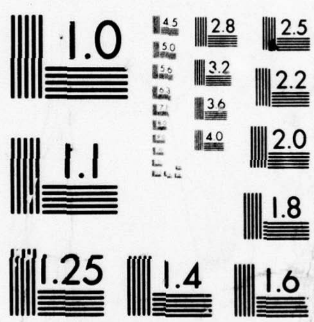
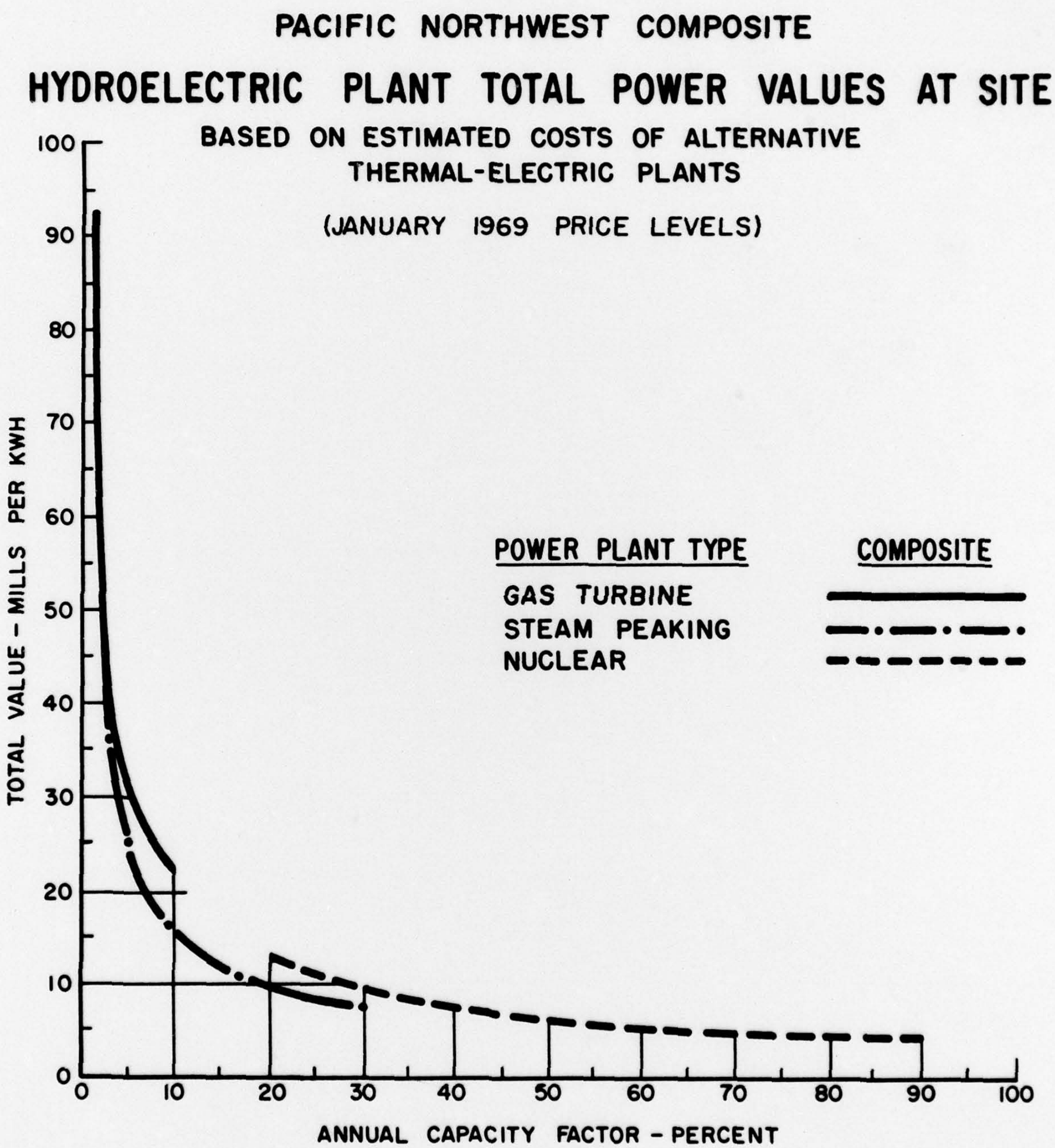


MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

Figure 23


PACIFIC NORTHWEST COMPOSITE
HYDROELECTRIC PLANT TOTAL POWER VALUES AT SITE
BASED ON ESTIMATED COSTS OF ALTERNATIVE THERMAL-ELECTRIC PLANTS
(JANUARY 1969 PRICE LEVELS)
TOTAL VALUE - MILLS PER KWH
0
10
20
30
40
50
60
70
80
90
100
ANNUAL CAPACITY FACTOR - PERCENT
POWER PLANT TYPE
COMPOSITE
GAS TURBINE
STEAM PEAKING
NUCLEAR

MEANS TO SATISFY DEMANDS

The previous chapters have discussed the existing electric power system and power requirements, future power requirements, the potential alternatives for meeting future power requirements, and a means for evaluating those alternatives. This chapter summarizes the sources of electric power in and for the Puget Sound Study Area such as: importation of power, conventional and pumped-storage hydroelectric generation, geothermal, fossil-fuel, and nuclear. Also presented is the projected power development to meet the demands for power in 1980, 2000 and 2020.

POWER SOURCES

IMPORTATION

The Puget Sound Area with a peak electric load of about 3,500 mw presently imports about 2,000 mw of peaking capacity to augment the 1,500 mw of peaking resources in the Area. The importation of electric energy is in about the same ratio with two-thirds of the load being met from outside sources. This importation is expected to continue as long as peaking capacity is surplus in areas outside of the Puget Sound Study Area.

Transmission planners are increasing the transmission capacities of the lines through the corridors of the Cascade Mountain Range to the east. These increases are for importing peaking capacity and some energy from the upper and middle Columbia River hydroelectric plants. The present corridors will meet their limits for transmission in about the 1990's, when the installed capacities at those plants will be at ultimate development. Therefore, no increase in importation is expected after the year 2000.

HYDROELECTRIC

Conventional

The Puget Sound Area presently has 1,210 mw of installed conventional hydroelectric capacity. An inventory of planning underway in hydroelectric development indicates an active interest in developing 558 mw by 1980 at the following existing and potential projects.

Project	Installed Capacity Megawatts	Average Annual Energy Million KWH
Snohomish Basin		
Upper Sultan	84	122
Middle Sultan	32	129
Lower Sultan	24	73
No. Fork Snoqualmie Mi. 11.7	23	73
No. Fork Snoqualmie Mi. 5.9	32	204
Pilchuck	4	--
Sub-Total	199	601
Skagit Basin		
Cascade	60	230
Cooper Creek	83	382
Thunder Creek diversion	--	362[1]
Lower Sauk	96	482
Additions to existing projects[2]		
Gorge	--	200
Diablo	120	150
Ross	--	368
Sub-Total	359	2,174
Total	558	2,775

[1] Increase in energy output at Ross power plant from proposed diversion from Thunder Creek to Ross Lake.

[2] Due to proposed increase of 125 feet in height of Ross Dam.

Tables 7 and 8 give additional data on these projects.

This appendix investigated 89 potential hydroelectric sites with a total installed capacity of 3,390 mw. Twenty-three alternate sites, also investigated, are not included in the total. The results of the investigation reveal that no sites approach feasibility from a single-purpose standpoint. The results are noted in Table 11, "Analysis of potential single-purpose hydroelectric projects."

Therefore, beyond 1980, it is expected that any addition of new conventional hydroelectric development will be multi-purpose projects where some other function or functions will help support the cost of dam and reservoir.

Pumped-Storage

The potential of pumped-storage hydroelectric development presents an entirely different picture from conventional hydroelectric, with more than 100 available sites at relatively low costs of $90 to $130 per kilowatt of installed capacity. However, pumped-storage provides peaking capacity with very little energy. The power system of the Northwest will not need the type of peaking capacity provided by pumped-storage until the late 1990's. Up to that time importation from outside the Study Area will supply most of the required peaking capacity. The mid-Columbia River plants are the major source and all of the peaking units at those plants will be installed prior to the year 2000.

By the year 2000, the Puget Sound Study Area will need about 1,300 mw of peaking and by the year 2020 the Study Area will need about 19,000 mw of peaking capacity. Pumped-storage will supply most of the peaking for those years and the interim periods. The section on "Hydroelectric Power" in the chapter on "Potential Development" has detailed information on pumped-storage. The chapter on "Value of Power" evaluates alternatives to conventional hydroelectric and pumped-storage plants.

Pumped-storage is in use, under development, or planned in other sections of the United States where electric energy is supplied primarily by large base-load thermal-electric systems.

GEOTHERMAL

Geothermal electric power development is relatively small in the United States. However, this is not true in New Zealand and other countries. As pointed out in the chapter on "Geothermal Power," this type of generation may be constructed in the Puget Sound Study Area, should more investigations be undertaken. On the basis that by the year 2000 geothermal power will be economic, planners have considered geothermal as a possible source for at least some future electric generation.

FOSSIL-FUEL

The five, utility-owned, fossil-fuel steam-electric plants in the Puget Sound Study Area have an installed capacity of 200 mw. These plants are operated on a standby basis and are not considered dependable for extended use. Most of these plants are old and will be phased out of operation by the 1990's. The two Diesel-electric plants in the Study Area have a total capacity of 2.3 mw. These plants are also operated on a standby basis.

The potential of coal-fired thermal-electric plants as an alternative source of electric energy in the Puget Sound Study Area is negligible. Very little of the 2.0 billion tons of coal reserves in the Study Area are considered economically mineable and shipping costs prohibit the use of coal for base-load firm energy plants.

Fossil-fuel electric generation by gas turbines, steam-electric, or diesel-electric, does have a place in the resources of the Study Area, when considered as an alternative pumped-storage for peaking. This is covered in the chapter on "Value of Power." The section on "Potential Fossil-Fuel Electric Plants" also points out the expected use of fossil-fuel.

NUCLEAR

The Puget Sound Study Area, Pacific Northwest, United States, and the large electricity consuming countries of the world look toward nuclear-fired steam-electric plants as the most economic alternative electric development as a means to satisfy future electric needs. Austria, for example, has developed most of its economic hydro. In 1958, that country had about 15 years of coal reserves left for fossil-fuel electric plants. At that time Austria decided to build all future fossil-fuel plants with the necessary facilities for conversion to nuclear fuel. This decision was based on confidence in research and development in the field of nuclear-fueled steam-electric plants as an economic alternative.

The section, "Nuclear Electric Plants," in the chapter on "Potential Development" discusses nuclear power and the various methods of providing

condenser cooling. The chapter, "Value of Power," evaluates nuclear-electric generation as an alternative to hydroelectric generation.

Nuclear power plants existing and under construction in the United States utilize light water reactors, generally of the boiling water and pressurized water type. An intermediate size high temperature gas cooled reactor plant is now under construction. Fast breeders are under extensive study, and two or three breeder prototypes will likely be built in the early 1970's. Electric power planners agree that even though larger units are under study, the 1,000 mw unit is a reasonable size for planning purposes.

Maximum Land and Water Requirements for Nuclear Power in the Puget Sound Study Area

As stated previously, nuclear power plants will be used primarily to supply base-load energy requirements in the Pacific Northwest including the Puget Sound Study Area. Hydroelectric generation, both from within and outside the Area, will assist in supplying the peaking generation required especially during the early years. The installation required for nuclear power generation by the year 2020 will be about 52,000 mw. This figure is obtained from Table 22, "Summary of requirements and resources." If all of the power requirements from nuclear power plants are met within the Area, the equivalent of fifty-two 1,000 mw plants on separate sites would be required. Considering that all of the power requirements were met by plants of one of the types of cooling systems discussed in the section on "Nuclear Electric Plants," the maximum land and water requirements for the Puget Sound Study Area for each type system would be:

1. Once-Through Cooling System:

The land requirements when plants are on large bodies of fresh or salt water of more than 3,000 feet across are:

350 acres x 52 plants = 18,200 acres

The water frontage land required would be about:

6,000 ft. per plant x 52 plants = 59 miles

Cooling water required:

1,600 cfs x 52 plants = 83,200 cfs

Consumptive water required:

1.2 cfs x 52 plants = 62 cfs

2. Evaporative Type Cooling Systems:

a. Natural draft or induced draft cooling towers:

Land required:

650 acres x 52 plants = 33,800 acres

Consumptive water required:

Evaporation:	32 cfs x 52 plants =	1,664 cfs
Blowdowns:	4 cfs x 52 plants =	208 cfs
	Total	1,872 cfs

b. Cooling ponds:

Land required:

Site area: 300 + acres above the pool requirements x 52 plants = 15,600 acres

Surface area of cooling ponds:

2,000 acres x 52 plants =	104,000 acres
Total land area:	119,600 acres

Consumptive water required:

60 cfs x 52 plants = 3,120 cfs

Water storage requirements:

20 ft. deep x 1,500 acres x 52 plants = 1,560,000 ac.ft.

The figures presented are for maximum requirements. Actually, several types of cooling systems and combinations thereof will probably be utilized. Also, multiple-unit sites will almost certainly be utilized, reducing the land requirements per megawatt of installed capacity.

Possible Nuclear Power Sites in the Puget Sound Study Area

The Bonneville Power Administration Research Report, "Nuclear Power Plant Siting in the Pacific Northwest," dated July 1, 1967, discusses the siting of nuclear power plants of 1,000 mw or more in the Puget Sound Area as follows:

The Puget Sound Area has many features advantageous to nuclear power plant siting:

1. A plentiful supply of cold water for cooling purposes.

2. Favorable tidal currents—at many locations—conducive to rapid dispersal of the plant effluent.

3. Protected deep water—close inshore—providing good access by sea.

4. Proximity to major load centers and major transmission facilities.

However, around Puget Sound, there are some siting complexities that stem from a high density, growing population, and, in some cases, restricted mixing in the waters of the Sound. The latter would tend to maximize surface temperature effects from effluent discharges. Acceptable once-through cooled sites may be developed at many locations. Three "once-through" example sites were chosen where population density and thermal mixing considerations appeared to be simultaneously optimized. These were:

1. A location in Northern Puget Sound (Example Site 1).

2. An island location (Example Site 2).

3. A location on the Strait of Juan de Fuca (Example Site 3).

The factors developed in analysis of these three sites should be applicable to other once-through cooled plant sites on the inland waters of Puget Sound. Two additional sites were also chosen for analysis east of the Puget Sound metropolitan area. Example Site 4, on the Skagit River, was treated as a cooling tower site although detailed study of local conditions may lend credence to a once-through cooled design or a hybrid system that permits partial cooling of the effluent water before it is discharged back to the river. Example Site 5, on a reservoir of the Nisqually River, was also specified as a cooling tower plant. The two cooling tower sites should typify many potential river locations in Western Washington.

Example Site 1: Puget Sound Mainland, Salt Water—This siting area lies northwest of Bellingham, Washington, in an area zoned for industrial development. It was selected for detailed analysis as representative of others located on the mainland abutting Puget Sound. Several siting arrangements appear feasible, depending upon availability of land not already developed or reserved for other (industrial) use.

This plan area is unique in that low population density, closeness of a major PNW industrial load, and availability of well-mixed water off shore represent a good combination of site characteristics. Test borings are required to determine whether sandy deposits that have been found to the southeast extend to this location. If not, the gravel till of the Vashon ice age—reportedly a massively compact mixture of clay, silt, sand, and gravel with a "concrete-like" nature which underlies this general area—may be quite suitable for foundation material. Depending upon land availability and demonstrated suitable foundation materials, several reactors could probably be located here.

A plant located at this example site is assumed to be established with a grade elevation of about 25 feet, some 9 feet above the highest credible approach of the sea. The plant utilizes a once-through coolant system with salt water coolant.

Example Site 2: Puget Sound—Island—Siting on Whidbey Island was analyzed to develop costs and other siting considerations relative to islands in Puget Sound. Island sites offer potential siting advantages in terms of lowered costs for the coolant system and ready access by marine transportation. A major disadvantage may be transmission costs if underwater cables must be employed.

The western shore of Whidbey Island offers several potential nuclear power site areas. Four were considered in this Study; each appeared capable of supporting several reactors. Two of these were south of the example site selected for detailed analysis, and one was to the north. Three of the four sites offered the possibility of cross-island pumping, a potential advantage where recirculation from the outfall to the intake lines might prove troublesome with another design arrangement. Cross-island pumping might also serve an antipollution role at some locations. The example site, for instance, was assumed to draw water from the bay on the east side of the island and discharge it to the west, after passage through the plant. The net flow induced into the eastern bay by the intake would assist in reducing pollution buildup (if present). This same principle could be applied near estuaries.

As mentioned, the example site is representative of several others along the west shore of Whidbey Island where tidal currents cause extensive mixing. The west shore may be capable of supporting a large nuclear power complex. Other sites on the Island would have different intake arrangements, and moderate changes in capital and operating costs would result. A diversity of underlying materials may

exists along the west shore. A lack of published data dictates the need for on-site studies to find those locations where compact materials exist.

Example Site 3: Strait of Juan de Fuca—Nuclear power reactor siting on the Strait of Juan de Fuca was analyzed as an extension of mainland and island sites in Puget Sound. Though distant from urban load centers, this area offers future siting potential.

Steep sea cliffs, thickly forested land, and remoteness of much of the coast from road and rail transportation tend to increase construction costs somewhat in this region. The terrain limits the number of good potential sites; however, several were identified. The example site selected for detailed analysis lies east of Port Angeles, and several others were identified west of that city. The sites further west along the Strait may have more favorable terrain features, while siting south of Port Townsend, facing Admiralty Inlet may also prove feasible. The Strait offers an abundance of cold water for cooling nuclear power plants. The currents at the example site require better definition, however, since the potential for circulation of warm effluent into the adjacent bay raises questions concerning local marine fish and shellfish resources habitat. The tolerance of these fishes to warm effluents or rapid temperature changes is unknown and needs to be determined.

The example site is believed to be underlain by outwash gravels resembling the Hanford outwash gravels, which have proven excellent for reactor foundation materials. Major excavation would be required to establish the grade at this location; in addition, the sea cliff at the site would have to be stabilized and protected against erosion.

Example Site 4: Puget Sound—River—Flexibility in selecting nuclear power plant sites increases when evaporative cooling systems are used for waste heat disposal. Many rivers, streams, and impoundments too small to supply plant coolant needs or to accept the effluent from a once-through-cooled plant will readily supply the make-up requirements of cooling towers. Rivers such as the Nooksack, Skagit, Skykomish, Snoqualmie, and Nisqually were briefly considered for supplying the cooling needs of nuclear power plants generating power for the Puget Sound metropolitan areas.

Many potential sites exist on these rivers, and two were selected for detailed analysis as representative of a number of others: a site on the Skagit River (Example Site 4); a site located on an impoundment of the Nisqually River (Example Site 5). Flooding potential, foundation materials undesirable for a Zone 3 earthquake area such as Puget Sound, unsuitable terrain, and population density appeared to rule out a number of local areas. In other cases, streams were found to suffer from lowflow in the dry season although impoundments might be considered for storing water to provide the average flow in such cases.

Example Site 4, located on the Skagit River, is typical of many other locations in the river valleys of the Puget Sound Area. Capital and operating costs in these situations should not be markedly different from that of Site 4. Similarly, plant design features would be expected to be essentially the same from site to site. Moderately high site preparation costs would be incurred in location above the river flood plain, and access would require construction of a bridge across the river. The river has sufficient flow to warrant consideration of a partial capacity once-through coolant system.

Waters of the Skagit River flowing past this site would not be highly appropriated. Water rights for cooling tower operation should be obtainable without compensation to others for loss of water rights.

Example Site 5: Puget Sound—Reservoir—Example Site 4 described a cooling tower situated on a river in the northern Puget Sound Area. Example Site 5 is located on an impoundment of the Nisqually River in the southern Puget Sound Area. It, too, would utilize cooling towers in place of a once-through coolant system. The features associated with this site should be typical of others located on hydroelectric power reservoirs of the western Cascades. Because the remoteness of the site precludes delivering the reactor pressure vessel intact, it was assumed that the vessel would be fabricated on-site.

The multiple uses to which this river is put, downstream of the proposed plant site, introduce additional siting considerations. Waters of this river are highly appropriated. There are downstream diversions of water for agricultural, municipal, or industrial use, but at the dam forming the reservoir, the predominant appropriation is for power generation. Water evaporated from cooling towers would amount to a depletion of water storage, except during periods of excess streamflow. Assuming the same utility owns both nuclear power plant and dam, the problem of resource balancing would be an internal one; otherwise, a power sharing agreement or equivalent cash

payments would be required to compensate the dam owners for water withheld from the turbines. No thermal effect on acquatic species would be contemplated since cooling towers are used. A condensation cloud might be expected above the towers over much of the year; preliminary calculations indicate that the cloud would not be expected to extend to ground level.

ENVIRONMENTAL CONSIDERATIONS FOR NUCLEAR POWER PLANT SITING BY THE STATE OF WASHINGTON

The land and water problems for each nuclear power plant site must be solved first. Environmental and biological solutions cannot be formulated in general before site selection, because they vary for each site. For example, cooling towers discharge about 35 cfs, which cannot be tolerated in some locations. Cooling ponds require less water and are encouraging from the multiple-use concept, but they have complex problems too. Temperature, which is a major item, is only part of the biological effect.

Agencies of the State of Washington, including the Department of Fisheries, Department of Water Resources, Department of Game, State Air Resources Control Board, State Water Pollution Control Commission, and others, review nuclear power plant siting proposals for such conditions as:

1. The site is not in conflict with long-range plans.
2. Does the site meet water quality standards?
3. What fish resources are involved?
4. Air quality control.
5. The effect of the site on total State environment.
6. Is the site being considered as part of a coordinated power program?
7. Recreation and aesthetic considerations.
8. Water and air quality on the positive side.
9. Geologic and seismic factors.

PROJECTED POWER DEVELOPMENT 1980, 2000, 2020

The projected power development for meeting power requirements in the Puget Sound Study Area is presented in Table 22, "Summary of requirements and resources." This information is also illustrated by the graphs on Figures 24 and 25, which compare the peak and energy requirements with the peak and energy resources.

REQUIREMENTS

The meeting of an electrical load incurs some losses. When these losses are included with the load, the total becomes a requirement. The reliability of electrical equipment must also be considered. Therefore, in addition to loads and losses, the electrical power system must have certain amounts of peak and energy in reserve which are included in the requirements. The estimated requirements for the Puget Sound Area for 1980, 2000 and 2020 at the top of Table 22 are from the chapter on "Future Electric Power Requirements."

EXISTING AND SCHEDULED RESOURCES

Imports

The importation of electric peak and energy is expected to increase through the 1990's when the Columbia River hydroelectric system will be completely developed. The importation of 13,400 mw peaking capacity and 5,000 mw average energy will remain the same for 2000 and 2020.

Resources of Puget Sound Area

The existing electric power systems have 1,210 mw of hydroelectric generation and 200 mw of fossil-fuel electric generation. By 1980 some of the older hydroelectric plants may be retired and all but about 30 mw of the fossil-fuel generation will be retired. Some interest has been shown in developing about 550 mw in new hydroelectric generation by 1980. These were discussed in this chapter and in the

"Power Sources" section. Therefore, by 1980 the Puget Sound Area should have a total of about 1,790 mw in resources. After 1980 the last of the fossil-fuel plants will be retired and the Area resources, exclusive of new thermal, will remain at about 1,760 mw through 2000 and 2020.

FUTURE RESOURCES

Additional Generation Demand by 1980 and 2000

The existing and scheduled resources and imports will meet the demand by 1980 as indicated in Item 7 of Table 22. However, by the year 2000 the Puget Sound Area will need additional generation of 13,530 mw of peaking capacity and 10,400 mw of energy shown in Item 8 of Table 22. The means for satisfying this additional demand is primarily by base load thermal installations. With confidence in the research being carried out in the field of geothermal generation, token amounts of 100 mw capacity and 80 mw energy are shown. There are no known planned developments for fossil-fuel generation.

The field of nuclear-electric generation has received much attention in recent years. Electric power planners expect that by the year 2000, the Study Area's additional demand of 12,100 mw peaking capacity and 10,300 mw energy will be met from that source.

There are several nuclear-electric power plant sites in the Puget Sound Study Area under investigation for possible production in the late 1970's or early 1980's. Among these sites are Cherry Point, northwest of Bellingham; Sequim, on the Olympic Peninsula, near Port Angeles; and Kicket Island, in the Whidbey Island area. A coordinated effort in scheduling the needed 12,000 mw is underway, taking into consideration the various environmental aspects required.

The nuclear plants will also contribute to the peaking capability. They are installed on the basis of energy, with a plant factor of 80-85 percent, which takes into consideration maintenance, refueling, and unscheduled outages.

Pumped-storage sites which meet the environmental considerations and are most economical will provide most of the additional peaking capacity needed. However, some fossil-fuel plants in the form of gas turbines may also be installed at locations near load centers to assist in meeting the demand. A combination of the two will produce the 1,330 mw of additional peaking needed by the year 2000.

Item 9 in Table 22 indicates that 13,530 mw of peaking capacity and 6,560 mw of energy will be installed between 1980 and 2000.

Additional Generation Demand by 2020

The additional generation demand by 2020, Item 10, Table 22 is 59,130 mw for peaking capacity and 34,740 mw for energy. Geothermal has again been given recognition for 130 mw with a total of 230 mw installed by 2020. The Puget Sound Area will need about 40,000 mw of nuclear-electric generation between 2000 and 2020. This will be a total of 52,100 mw installed capacity attributed to nuclear-electric generation from 1980 to 2020. Pumped-storage and fossil-fuel plants will fulfill the required 19,000 mw needed to round out the demand of 59,130 mw in the period between 2000 and 2020.

Because of the competition for the use of land for purposes other than power, there is an urgent need for the proper authorities to take immediate steps for reserving desirable pumped-storage and thermal-electric sites; also, for conducting proper investigations to assure public acceptance of these sites for future power developments.

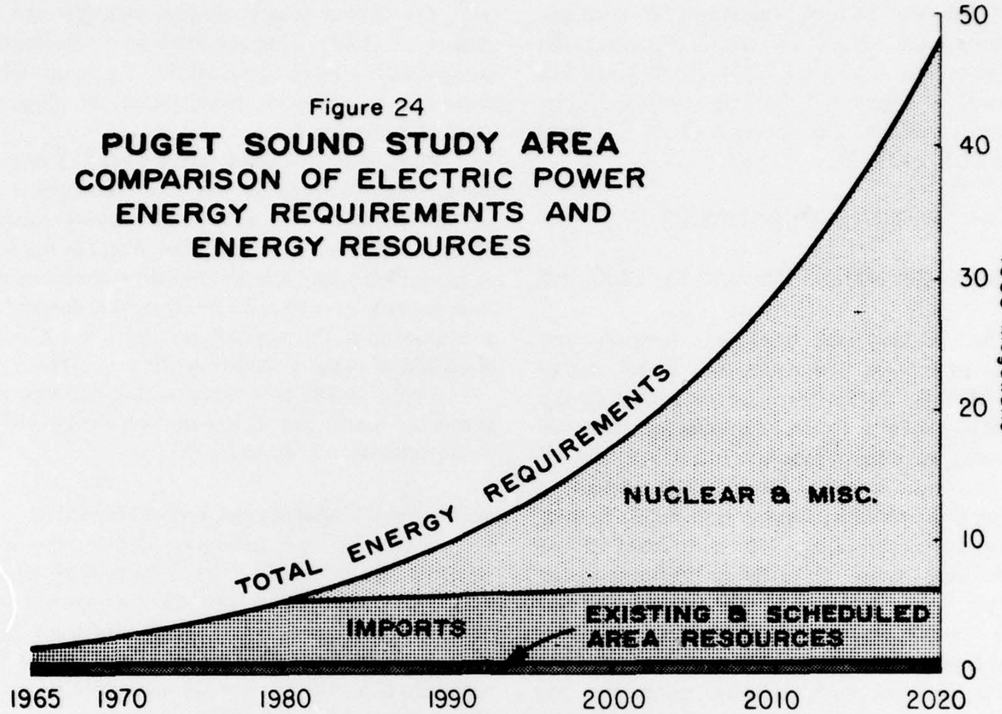


Figure 24

PUGET SOUND STUDY AREA
COMPARISON OF ELECTRIC POWER ENERGY REQUIREMENTS AND ENERGY RESOURCES

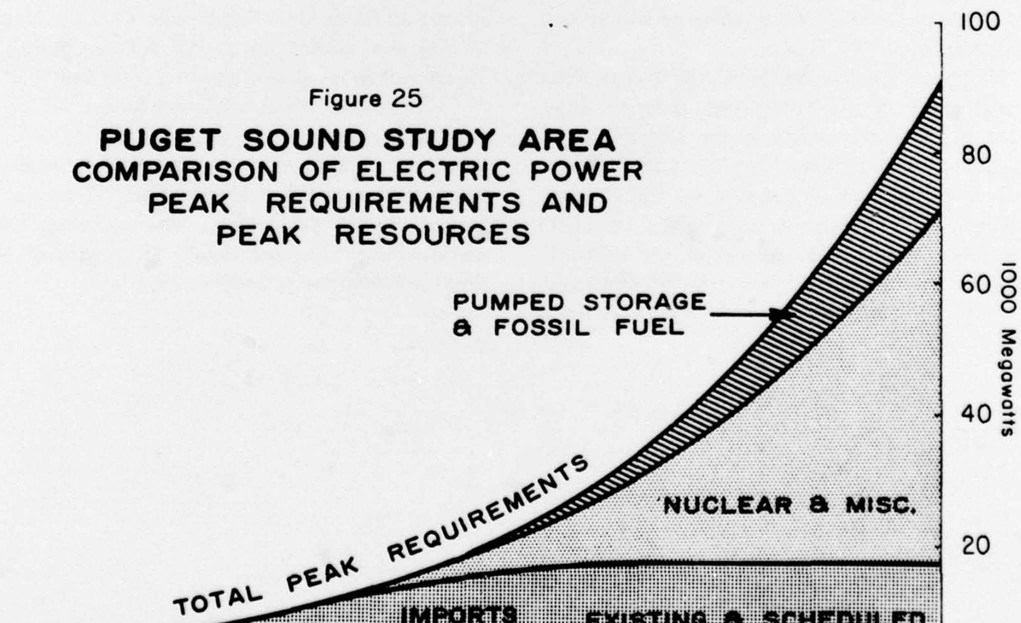


Figure 25

PUGET SOUND STUDY AREA
COMPARISON OF ELECTRIC POWER PEAK REQUIREMENTS AND PEAK RESOURCES

TABLE 22. Summary of requirements and resources, means to satisfy generation demands, Puget Sound Area, December peak and critical period average energy

	Prior to 1980 Peaking Capacity	Prior to 1980 Annual Energy	1980-2000 Peaking Capacity	1980-2000 Annual Energy	2000-2020 Peaking Capacity	2000-2020 Annual Energy
Requirements						
1. Area requirements	9,500	5,500	28,100	16,270	78,800	45,700
2. Reserves	230	30	2,170	530	10,600	2,000
3. Total requirements	9,730	5,530	30,270	16,800	89,400	47,700
Existing and Scheduled Resources						
4. Imports						
Other ownership resources out of area	6,900	4,190	13,400	5,000	13,400	5,000
Own resources out of area	1,110	560	1,580	610	1,580	610
Total importations	8,010	4,750	14,980	5,610	14,980	5,610
5. Area resources						
Hydro generation	1,760	790	1,760	790	1,760	790
Fossil-fuel generation	30	20	0	0	0	0
Total generation from area sources	1,790	810	1,760	790	1,760	790
6. Total existing and scheduled resources and imports	9,800	5,560	16,740	6,400	16,740	6,400
Future Resource Requirements						
7. Additional generation demand by 1980	0	0				
8. Additional generation demand by 2000			13,530	10,400		
Means to satisfy demands						
Thermal base load installations						
Geothermal			100	80		
Fossil-fuel			0	0		
Nuclear			12,100[1]	10,300		
Additional peaking from pumped-storage and fossil-fuel			1,330	50(50)[2]		
9. Total resources placed in service between 1980-2000					13,530	6,560[3]
10. Additional generation demand by 2020					59,130	34,740
Means to satisfy demands						
Thermal base load installations						
Geothermal					130	80
Fossil-fuel					0	0
Nuclear						
Total					40,000	33,560[4]
Energy for pumped-storage pumping						(2,400)
Additional peaking						
Pumped-storage					16,000	1,600
Fossil-fuel					3,000	300

[1] Capacity installations in nuclear plants based on energy production at 80-85 percent annual capacity factors.

[2] Energy deficiency equaling net of the energy produced by the pumped-storage projects when peaking and the thermal energy required for pumping to replenish reservoirs during off-peak periods.

[3] The nuclear added by 2000 assumed to operate at a lower capacity factor through 2020. Energy also includes geothermal, pumped-storage and thermal peaking operating with same output of energy as shown for 2000.

[4] Includes additional 800 mw energy (2400-1600) required in pumped-storage pumping.

GLOSSARY

ELECTRIC POWER

BOILER MAKE-UP WATER–Water required to replace the loss of water in the thermodynamic cycle.

BRITISH THERMAL UNIT (Btu)–The standard unit for measurement of the amount of heat energy, such as the heat content of fuel. One Btu is approximately equal to the amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit at 60°F. One Btu equals 778.17 foot-pounds.

CAPACITY FACTOR (ELECTRIC POWER)–The ratio of the average load on the generating plant for the period of time considered to the capacity rating of the plant.

CONDENSER COOLING WATER–Water required to condense the steam after its passage from the steam turbine.

COOLING WATER CONSUMPTION (POWER)–The cooling water withdrawn from the source supplying a generating plant which is lost to the atmosphere. Caused primarily by evaporation due to the temperature rise in the cooling water as it passes through the condenser. The amount of consumption (loss) is dependent on the type of cooling employed–flow-through, cooling pond, or cooling tower.

COOLING WATER LOAD–Heat energy dissipated by the cooling water.

COOLING WATER REQUIREMENT (POWER)–The amount of water needed to pass through the condensing unit in order to condense the steam to water. This amount is dependent on the type of cooling employed.

DEPENDABLE CAPACITY–The load-carrying ability of a station or system under adverse conditions for the time interval and period specified when related to the characteristics of the load to be supplied. Dependable capacity of a system includes net firm power purchases.

FIRM POWER–Power intended to have assured availability to the customer to meet all or any agreed upon portion of his load requirements.

GENERATOR EFFICIENCY–The ratio of the energy output of the generator to the energy input under specified conditions.

GIGAWATT (gw)–One million kilowatts.

HEAT LOSS FROM BOILER FURNACE–Heat energy loss from the combustion chamber is primarily through the stack. Some of this heat is recovered by external equipment, such as preheaters, etc. This energy is not part of the cooling water load.

HEAT LOSS FROM ELECTRIC GENERATOR–Heat lost in converting the mechanical turbine energy into generator electric energy. This heat energy is generally dissipated by a fluid flowing in a closed circuit which is cooled by water. Thus, it is a part of the cooling water load.

HEAT RATE–A measure of the thermal efficiency of a generating station. It is computed by dividing the total Btu content of the fuel burned (or heat released from a nuclear reactor) by the gross energy generated, generally expressed as Btu per kilowatt-hour.

KILOVOLT (kv)–One thousand volts.

KILOWATT (kw)–The electric unit of power which equals 1,000 watts or 1.341 horsepower.

KILOWATT-HOUR (kwh)–The basic unit of electric energy. It equals one kilowatt of power applied for one hour.

LOAD FACTOR–The ratio of the average load over a designated period to the peak-load occurring in that period.

MEGAWATT (mw)–One thousand kilowatts.

MEGAWATT-HOUR (mwh)–One thousand kilowatt-hours.

NET HEAT RATE–A measure of the thermal efficiency of a generating station including station use. It is computed by dividing the total Btu content of the fuel burned (or of heat released from a nuclear reactor) by the net energy generated, generally expressed as Btu per net kilowatt-hour.

PEAK LOAD–The maximum load in a stated period of time. Usually it is the maximum integrated load over an interval of one hour which occurs during the year, month, week, or day. It is used interchangeably with peak demand.

PLANT EFFICIENCY–The ratio of the energy delivered from the plant to the energy received by it under specified conditions.

PLANT FACTOR–The ratio of the average load on the plant for the period of time considered to the aggregate rating of all the generating equipment installed in the plant.

POWER SUPPLY AREA (PSA)–Geographic grouping of electric power supplies as established by the Federal Power Commission in accordance with utility service areas.

RESERVE CAPACITY (ELECTRIC POWER)–The difference between the peak load and the generating capacity available.

THERMAL EFFICIENCY–The ratio of the amount of energy produced to the total Btu content of the fuel consumed, usually expressed as a heat rate (Btu per kwh).

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